ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 50, 51, 52, 53, and 58

[EPA–HQ–OAR–2008–0699; FRL–9933–18–OAR]

RIN 2060–AP38

National Ambient Air Quality Standards for Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Based on its review of the air quality criteria for ozone (O_3) and related photochemical oxidants and national ambient air quality standards (NAAQS) for O_3, the Environmental Protection Agency (EPA) is revising the primary and secondary NAAQS for O_3 to provide requisite protection of public health and welfare, respectively. The EPA is revising the levels of both standards to 0.070 parts per million (ppm), and retaining their indicators (O_3), forms (fourth-highest daily maximum, averaged across three consecutive years) and averaging times (eight hours). The EPA is making corresponding revisions in data handling conventions for O_3 and changes to the Air Quality Index (AQI); revising regulations for the prevention of significant deterioration (PSD) program to add a transition provision for certain applications; and establishing exceptional events schedules and providing information related to implementing the revised standards. The EPA is also revising the O_3 monitoring seasons, the Federal Reference Method (FRM) for monitoring O_3 in the ambient air, Federal Equivalent Method (FEM) analyzer performance requirements, and the Photochemical Assessment Monitoring Stations (PAMS) network. Along with exceptional events schedules related to implementing the revised O_3 standards, the EPA is applying this same schedule approach to other future new or revised NAAQS and removing obsolete regulatory language for expired exceptional events deadlines. The EPA is making minor changes to the procedures and time periods for evaluating potential FRMs and equivalent methods, including making the requirements for nitrogen dioxide (NO_2) consistent with the requirements for O_3, and removing an obsolete requirement for the annual submission of Product Manufacturing Checklists by manufacturers of FRMs and FEMs for monitors of fine and coarse particulate matter. For a more detailed summary, see the Executive Summary below.

DATES: The final rule is effective on December 28, 2015.

ADDRESSES: EPA has established a docket for this action (Docket ID No. EPA–HQ–OAR–2008–0699) and a separate docket, established for the Integrated Science Assessment (ISA) (Docket No. EPA–HQ–ORD–2011–0050), which has been incorporated by reference into the rulemaking docket. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the docket index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and may be viewed, with prior arrangement, at the EPA Docket Center. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, WJC West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Air and Radiation Docket and Information Center is (202) 566–1742. For additional information about EPA's public docket, visit the EPA Docket Center homepage at: *http://www.epa.gov/epahome/dockets.htm*.

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SUPPLEMENTARY INFORMATION:

General Information

Availability of Related Information

A number of the documents that are relevant to this action are available through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN) Web site (*http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*). These documents include the *Integrated Science Assessment for Ozone* (U.S. EPA, 2013), available at *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_2008_isa.html*; the *Health Risk and Exposure Assessment* and the *Welfare Risk and Exposure Assessment for Ozone,* Final Reports (HREA and WREA, respectively; U.S. EPA, 2014a, 2014b), available at *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_2008_rea.html*; and the *Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards* (PA; U.S. EPA, 2014c), available at *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_2008_pa.html*. These and other related documents are also available for inspection and copying in the EPA docket identified above.

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The following topics are discussed in this preamble:

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Executive Summary

This section summarizes information about the purpose of this regulatory action, the major provisions of this action, and provisions related to implementation.

Purpose of This Regulatory Action

Sections 108 and 109 of the Clean Air Act (CAA) govern the establishment, review, and revision, as appropriate, of the NAAQS to protect public health and welfare. The CAA requires the EPA to periodically review the air quality criteria—the science upon which the standards are based—and the standards themselves. This rulemaking is being conducted pursuant to these statutory requirements. The schedule for completing this review is established by a federal court order, which requires that the EPA make a final determination by October 1, 2015.

The EPA completed its most recent review of the NAAQS for O_3 in 2008. As a result of that review, EPA took four principal actions: (1) Revised the level of the 8-hour primary standard to 0.075 ppm; (2) expressed the standard to three decimal places; (3) revised the 8-hour secondary standard by making it identical to the revised primary standard; and (4) made conforming changes to the AQI.

In subsequent litigation, the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit) upheld the EPA's 2008 primary standard but remanded the 2008 secondary standard (*Mississippi* v. *EPA,* 744 F. 3d 1334 [D.C. Cir. 2013]). With respect to the primary standard, the court held that the EPA reasonably determined that the existing primary standard, set in 1997, did not protect public health with an adequate margin of safety and required revision. In upholding the EPA's revised primary standard, the court dismissed arguments that the EPA should have adopted a more stringent standard. The court remanded the secondary standard to the EPA after finding that the EPA's justification for setting the secondary standard identical to the revised 8-hour primary standard violated the CAA because the EPA had not adequately explained how that standard provided the required public welfare protection. In remanding the 2008 secondary standard, the court did not vacate it. The EPA has addressed the court's remand with this final action.

This final action reflects the Administrator's conclusions based on a review of the O_3 NAAQS that began in September 2008, and also concludes the EPA's reconsideration of the 2008 decision that it initiated in 2009 and subsequently consolidated with the current review. In conducting this review, the EPA has carefully evaluated the currently available scientific literature on the health and welfare effects of O_3, focusing particularly on the new literature available since the conclusion of the previous review in 2008. Between 2008 and 2014, the EPA prepared draft and final versions of the Integrated Science Assessment, the Health and Welfare Risk and Exposure Assessments, and the Policy Assessment. Multiple drafts of these documents were subject to public review and comment, and, as required by the CAA, were peer-reviewed by the Clean Air Scientific Advisory Committee (CASAC), an independent scientific advisory committee established pursuant to the CAA and charged with providing advice to the Administrator.

The EPA proposed revisions to the primary and secondary O_3 NAAQS on December 17, 2014 (79 FR 75234), and provided a 3-month period for submission of comments from the public. In addition to written comments submitted to EPA, comments were also provided at public hearings held in Washington, DC, and Arlington, Texas, on January 29, 2015, and in Sacramento, California, on February 2, 2015. After consideration of public comments and the advice from the CASAC, the EPA has developed this final rulemaking, which is the final step in the review process.

In this rulemaking, the EPA is revising the suite of standards for O_3 to provide requisite protection of public health and welfare. In addition, the EPA is updating the AQI, and making changes in the data handling conventions and ambient air monitoring, reporting, and network design requirements to correspond with the changes to the O_3 NAAQS.

Summary of Major Provisions

With regard to the primary standard, the EPA is revising the level of the standard to 0.070 ppm to provide increased public health protection against health effects associated with long- and short-term exposures. The EPA is retaining the indicator (O_3), averaging time (8-hour) and form (annual fourth-highest daily maximum, averaged over 3 years) of the existing standard. This action provides increased protection for children, older adults, and people with asthma or other lung diseases, and other at-risk populations against an array of adverse health effects that include reduced lung function, increased respiratory symptoms and pulmonary inflammation; effects that contribute to emergency department visits or hospital admissions; and mortality.

The decisions on the adequacy of the current standard and the appropriate level for the revised standard are based on an integrative assessment of an extensive body of new scientific evidence, which substantially strengthens what was known about O_3-related health effects in the last review. The revised standard also reflects consideration of a quantitative risk assessment that estimates public health risks likely to remain upon just meeting the current and various alternative standards. Based on this information, the Administrator concludes that the current primary O_3 standard is not requisite to protect public health with an adequate margin of safety, as required by the CAA, and that revision of the level to 0.070 ppm is warranted to provide the appropriate degree of increased public health protection for at-risk populations against an array of adverse health effects. In concluding that a revised primary standard set at a level of 0.070 ppm is requisite to protect public health with an adequate margin of safety, the Administrator relies on several key pieces of information, including: (a) A level of 0.070 ppm is well below the O_3 exposure concentration shown to cause the widest range of respiratory effects (*i.e.,* 0.080 ppm) and is below the lowest O_3 exposure concentration shown to cause the adverse combination of decreased lung function and increased respiratory symptoms (*i.e.,* 0.072 ppm); (b) a level of 0.070 ppm will eliminate, or nearly eliminate, repeated occurrence of these O_3 exposure concentrations (this is important because the potential for adverse effects increases with frequency of occurrence); (c) a level of 0.070 ppm will protect the large majority of the population, including children and people with asthma, from lower exposure concentrations, which can cause lung function decrements and airway inflammation in some people (*i.e.,* 0.060 ppm); and (d) a level of 0.070 ppm will result in important reductions in the risk of O_3-induced lung function decrements as well as the risk of O_3-associated hospital admissions, emergency department visits, and mortality. In addition, the revised level of the primary standard is within the range that CASAC advised the Agency to consider.

The EPA is also revising the level of the secondary standard to 0.070 ppm to provide increased protection against vegetation-related effects on public welfare. The EPA is retaining the indicator (O_3), averaging time (8-hour) and form (annual fourth-highest daily maximum, averaged over 3 years) of the existing secondary standard. This action, reducing the level of the standard, provides increased protection for natural forests in Class I and other similarly protected areas against an array of vegetation-related effects of O_3. The Administrator is making this decision based on judgments regarding the currently available welfare effects evidence, the appropriate degree of public welfare protection for the revised standard, and currently available air quality information on seasonal cumulative exposures that may be allowed by such a standard.

In making this decision on the secondary standard, the Administrator focuses on O_3 effects on tree seedling growth as a proxy for the full array of vegetation-related effects of O_3, ranging from effects on sensitive species to broader ecosystem-level effects. Using this proxy in judging effects to public welfare, the Administrator has concluded that the requisite protection will be provided by a standard that generally limits cumulative seasonal exposures to 17 ppm-hours (ppm-hrs) or lower, in terms of a 3-year W126 index. Based on air quality analyses which indicate such control of cumulative seasonal exposures will be achieved with a standard set at a level of 0.070 ppm (and the same indicator, averaging time, and form as the current standard), the Administrator concludes that a standard revised in this way will provide the requisite protection. In addition to providing protection of natural forests from growth-related effects, the revised standard is also expected to provide increased protection from other effects of potential public welfare significance, including crop yield loss and visible foliar injury. Thus, based on all of the information available in this review, the Administrator concludes that the current secondary O_3 standard is not requisite to protect public welfare as required by the CAA, and that this revision will provide appropriate protection against known or anticipated adverse effects to the public welfare.

Provisions Related to Implementation

As directed by the CAA, reducing pollution to meet NAAQS always has been a shared task, one involving the federal government, states, tribes and local air agencies. This partnership has proved effective since the EPA first issued O_3 standards more than three decades ago, and is evidenced by significantly lower O_3 levels throughout the country. To provide a foundation that helps air agencies build successful strategies for attaining new O_3 standards, the EPA will continue to move forward with federal regulatory programs, such as the final Tier 3 motor vehicle emissions standards. To facilitate the development of CAA-compliant implementation plans and strategies to attain new standards, the EPA intends to issue timely and appropriate implementation guidance and, where appropriate and consistent with the law, new rulemakings to streamline regulatory burdens and provide flexibility in implementation. Given the regional nature of O_3 air pollution, the EPA will continue to work with states to address interstate transport of O_3 and O_3 precursors. The EPA also intends to work closely with states to identify locations affected by high background concentrations on high O_3 days due to stratospheric intrusions of O_3, wildfire O_3 plumes, or long-range transport of O_3 from sources outside the U.S. and ensure that the appropriate CAA regulatory mechanisms are employed. To this end, the EPA will be proposing revisions to the 2007 Exceptional Events Rule and related draft guidance addressing the effects of wildfires.

In addition to revising the primary and secondary standards, this action is changing the AQI to reflect the revisions to the primary standard and also making corresponding revisions in data handling conventions for O_3, extending the O_3 monitoring season in 33 states, revising the requirements for the PAMS network, and revising regulations for the PSD permitting program to add a provision grandfathering certain pending permits from certain requirements with respect to the revised standards. The preamble also provides schedules and information related to implementing the revised standards.

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The rule also contains revisions to the schedules associated with exceptional events demonstration submittals for the revised O_3 standards and other future revised NAAQS, and makes minor changes related to monitoring for other pollutants.

I. Background

A. Legislative Requirements

Two sections of the CAA govern the establishment and revision of the NAAQS. Section 108 (42 U.S.C. 7408) directs the Administrator to identify and list certain air pollutants and then to issue air quality criteria for those pollutants. The Administrator is to list those air pollutants that in her ''judgment, cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;'' ''the presence of which in the ambient air results from numerous or diverse mobile or stationary sources;'' and ''for which . . . [the Administrator] plans to issue air quality criteria ....'' Air quality criteria are intended to ''accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of [a] pollutant in the ambient air ....'' 42 U.S.C. 7408(b). Section 109 (42 U.S.C. 7409) directs the Administrator to propose and promulgate ''primary'' and ''secondary'' NAAQS for pollutants for which air quality criteria are issued. Section 109(b)(1) defines a primary standard as one ''the attainment and maintenance of which in the judgment of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health.'' [1] A secondary standard, as defined in section 109(b)(2), must ''specify a level of air quality the attainment and maintenance of which, in the judgment of the Administrator, based on such criteria, is requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of [the] pollutant in the ambient air.'' [2]

The requirement that primary standards provide an adequate margin of safety was intended to address uncertainties associated with inconclusive scientific and technical information available at the time of standard setting. It was also intended to provide a reasonable degree of protection against hazards that research has not yet identified. See *Mississippi* v. *EPA,* 744 F. 3d 1334, 1353 (D.C. Cir. 2013); *Lead Industries Association* v. *EPA,* 647 F.2d 1130, 1154 (D.C Cir 1980); *American Petroleum Institute* v. *Costle,* 665 F.2d 1176, 1186 (D.C. Cir. 1981); *American Farm Bureau Federation* v. *EPA,* 559 F. 3d 512, 533 (D.C. Cir. 2009); *Association of Battery Recyclers* v. *EPA,* 604 F. 3d 613, 617–18 (D.C. Cir. 2010). Both kinds of uncertainties are components of the risk associated with pollution at levels below those at which human health effects can be said to occur with reasonable scientific certainty. Thus, in selecting primary standards that provide an adequate margin of safety, the Administrator is seeking not only to prevent pollution levels that have been demonstrated to be harmful but also to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. The CAA does not require the Administrator to establish a primary NAAQS at a zero-risk level or at background concentrations, see *Lead Industries* v. *EPA,* 647 F.2d at 1156 n.51; *Mississippi* v. *EPA,* 744 F. 3d at 1351, but rather at a level that reduces risk sufficiently so as to protect public health with an adequate margin of safety.

In addressing the requirement for an adequate margin of safety, the EPA considers such factors as the nature and severity of the health effects, the size of sensitive population(s) [3] at risk, and the kind and degree of the uncertainties that must be addressed. The selection of any particular approach for providing an adequate margin of safety is a policy choice left specifically to the Administrator's judgment. See *Lead Industries Association* v. *EPA,* 647 F.2d at 1161–62; *Mississippi,* 744 F. 3d at 1353.

In setting primary and secondary standards that are ''requisite'' to protect public health and welfare, respectively, as provided in section 109(b), the EPA's task is to establish standards that are neither more nor less stringent than necessary for these purposes. In so doing, the EPA may not consider the costs of implementing the standards. See generally, *Whitman* v. *American Trucking Associations,* 531 U.S. 457, 465–472, 475–76 (2001). Likewise, ''[a]ttainability and technological feasibility are not relevant considerations in the promulgation of national ambient air quality standards.'' *American Petroleum Institute* v. *Costle,* 665 F. 2d at 1185.

Section 109(d)(1) requires that ''not later than December 31, 1980, and at 5-year intervals thereafter, the Administrator shall complete a thorough review of the criteria published under section 108 and the national ambient air quality standards . . . and shall make such revisions in such criteria and standards and promulgate such new standards as may be appropriate ....'' Section 109(d)(2) requires that an independent scientific review committee ''shall complete a review of the criteria ....and the national primary and secondary ambient air quality standards.......... and shall recommend to the Administrator any new.......... standards and revisions of existing criteria and standards as may be appropriate.............'' Since the early 1980's, the CASAC [4] has performed this independent review function.

B. Related Control Programs

States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. The EPA performs an oversight function, and as necessary takes actions to ensure CAA objectives are achieved. Under section 110 of the CAA, and related provisions, states submit, for the EPA's approval, state implementation plans (SIPs) that provide for the attainment and maintenance of such standards through control programs directed to sources of the relevant pollutants. The states, in conjunction with the EPA, also administer the PSD program (CAA sections 160 to 169) which is a pre-construction permit program designed to prevent significant deterioration in air quality. In addition, federal programs provide for nationwide reductions in emissions of O_3 precursors and other air pollutants through new source performance standards for stationary sources under section 111 of the CAA and the federal motor vehicle and motor vehicle fuel control program under title II of the CAA (sections 202

[1] The legislative history of section 109 indicates that a primary standard is to be set at ''the maximum permissible ambient air level...........which will protect the health of any [sensitive] group of the population,'' and that, for this purpose, ''reference should be made to a representative sample of persons comprising the sensitive group rather than to a single person in such a group.'' S. Rep. No. 91–1196, 91st Cong., 2d Sess. 10 (1970).

[2] Welfare effects as defined in section 302(h) (42 U.S.C. 7602(h)) include, but are not limited to, ''effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being.''

[3] As used here with regard to human populations, and similarly throughout this document, the term ''population'' refers to people having a quality or characteristic in common, including a specific pre-existing illness or a specific age or lifestage.

[4] Lists of CASAC members and of members of the CASAC Ozone Review Panel are accessible from: *http://yosemite.epa.gov/sab/sabpeople.nsf/WebCommittees/CASAC.*

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to 250), which involves controls for emissions from mobile sources and controls for the fuels used by these sources. For some stationary sources, the national emissions standards for hazardous air pollutants under section 112 of the CAA may provide ancillary reductions in O_3 precursors.

After the EPA establishes a new or revised NAAQS, the CAA directs the EPA and the states to take steps to ensure that the new or revised NAAQS are met. One of the first steps, known as the initial area designations, involves identifying areas of the country that are not meeting the new or revised NAAQS along with the nearby areas that contain emissions sources that contribute to the areas not meeting the NAAQS. For areas designated ''nonattainment,'' the responsible states are required to develop SIPs to attain the standards. In developing their attainment plans, states first take into account projected emission reductions from federal and state rules that have been already adopted at the time of plan submittal. A number of significant emission reduction programs that will lead to reductions of O_3 precursors are in place today or are expected to be in place by the time revised SIPs will be due. Examples of such rules include the Nitrogen Oxides (NO_X) SIP Call and Cross-State Air Pollution Rule (CSAPR),[5] regulations controlling on-road and non-road engines and fuels, hazardous air pollutant rules for utility and industrial boilers, and various other programs already adopted by states to reduce emissions from key emissions sources. States will then evaluate the level of additional emission reductions needed for each nonattainment area to attain the O_3 standards ''as expeditiously as practicable,'' and adopt new state regulations as appropriate. Section VIII of this preamble includes additional discussion of designation and implementation issues associated with the revised O_3 NAAQS.

C. Review of Air Quality Criteria and Standards for O_3

The EPA first established primary and secondary NAAQS for photochemical oxidants in 1971 (36 FR 8186, April 30, 1971). The EPA set both primary and secondary standards at 0.08 ppm,[6] as a 1-hour average of total photochemical oxidants, not to be exceeded more than one hour per year. The EPA based the standards on scientific information contained in the 1970 *Air Quality Criteria for Photochemical Oxidants* (AQCD; U.S. DHEW, 1970). The EPA initiated the first periodic review of the NAAQS for photochemical oxidants in 1977. Based on the 1978 AQCD (U.S. EPA, 1978), the EPA published proposed revisions to the original NAAQS in 1978 (43 FR 26962, June 22, 1978) and final revisions in 1979 (44 FR 8202, February 8, 1979). At that time, the EPA revised the level of the primary and secondary standards from 0.08 to 0.12 ppm and changed the indicator from photochemical oxidants to O_3, and the form of the standards from a deterministic (*i.e.,* not to be exceeded more than one hour per year) to a statistical form. This statistical form defined attainment of the standards as occurring when the expected number of days per calendar year with maximum hourly average concentration greater than 0.12 ppm equaled one or less.

Following the EPA's decision in the 1979 review, the city of Houston challenged the Administrator's decision arguing that the standard was arbitrary and capricious because natural O_3 concentrations and other physical phenomena in the Houston area made the standard unattainable in that area. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) rejected this argument, holding (as noted above) that attainability and technological feasibility are not relevant considerations in the promulgation of the NAAQS. The court also noted that the EPA need not tailor the NAAQS to fit each region or locale, pointing out that Congress was aware of the difficulty in meeting standards in some locations and had addressed this difficulty through various compliance related provisions in the CAA. See *API* v. *Costle,* 665 F.2d 1176, 1184–6 (D.C. Cir. 1981).

In 1982, the EPA announced plans to revise the 1978 AQCD (47 FR 11561; March 17, 1982), and, in 1983, the EPA initiated the second periodic review of the O_3 NAAQS (48 FR 38009; August 22, 1983). The EPA subsequently published the 1986 AQCD (U.S. EPA, 1986) and the 1989 Staff Paper (U.S. EPA, 1989). Following publication of the 1986 AQCD, a number of scientific abstracts and articles were published that appeared to be of sufficient importance concerning potential health and welfare effects of O_3 to warrant preparation of a Supplement (U.S. EPA, 1992). In August of 1992, under the terms of a court order, the EPA proposed to retain the existing primary and secondary standards based on the health and welfare effects information contained in the 1986 AQCD and its 1992 Supplement (57 FR 35542, August 10, 1992). In March 1993, the EPA announced its decision to conclude this review by affirming its proposed decision to retain the standards, without revision (58 FR 13008, March 9, 1993).

In the 1992 notice of its proposed decision in that review, the EPA announced its intention to proceed as rapidly as possible with the next review of the air quality criteria and standards for O_3 in light of emerging evidence of health effects related to 6- to 8-hour O_3 exposures (57 FR 35542, August 10, 1992). The EPA subsequently published the AQCD and Staff Paper for the review (U.S. EPA, 1996a,b). In December 1996, the EPA proposed revisions to both the primary and secondary standards (61 FR 65716, December 13, 1996). With regard to the primary standard, the EPA proposed to replace the then-existing 1-hour primary standard with an 8-hour standard set at a level of 0.08 ppm (equivalent to 0.084 ppm based on the proposed data handling convention) as a 3-year average of the annual third-highest daily maximum 8-hour concentration. The EPA proposed to revise the secondary standard either by setting it identical to the proposed new primary standard or by setting it as a new seasonal standard using a cumulative form. The EPA completed this review in 1997 by setting the primary standard at a level of 0.08 ppm, based on the annual fourth-highest daily maximum 8-hour average concentration, averaged over three years, and setting the secondary standard identical to the revised primary standard (62 FR 38856, July 18, 1997). In reaching her decision on the primary standard, the Administrator identified several reasons supporting her decision to reject a potential alternate standard set at 0.07 ppm, including first the fact that no CASAC panel member supported a standard level lower than 0.08 ppm and her consideration of the scientific uncertainties with regard to the health effects evidence for exposure concentrations below 0.08 ppm. In addition to those reasons, the Administrator noted that a standard set

[5] The Cross-State Air Pollution Rule was upheld by the Supreme Court in *Environmental Protection Agency* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584 (2014), and remanded to the D.C. Circuit for further proceedings. The D.C. Circuit issued its decision on remand from the Supreme Court on July 28, 2015, remanding CSAPR to EPA, without vacating the rule, for EPA to reconsider certain emission budgets for certain States (*EME Homer City Generation, L.P.* v. *Environmental Protection Agency,* No. 11–1302, 2015 WL 4528137 [D.C. Cir. July 28, 2015]).

[6] Although the level of the 2008 O_3 standards are specified in the units of ppm (*i.e.,* 0.075 ppm), O_3 concentrations are described using the units of parts per billion (ppb) in several sections of this notice (*i.e.,* sections II, III, IV and VI) for consistency with the common convention for information discussed in those sections. In ppb, 0.075 ppm is equivalent to 75.

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at a level of 0.07 ppm would be closer to peak background concentrations that infrequently occur in some areas due to nonanthropogenic sources of O_3 precursors (62 FR 38856, 38868; July 18, 1997).

On May 14, 1999, in response to challenges by industry and others to the EPA's 1997 decision, the D.C. Circuit remanded the O_3 NAAQS to the EPA, finding that section 109 of the CAA, as interpreted by the EPA, effected an unconstitutional delegation of legislative authority. *American Trucking Assoc.* vs. *EPA,* 175 F.3d 1027, 1034–1040 (D.C. Cir. 1999) (''*ATA I*''). In addition, the court directed that, in responding to the remand, the EPA should consider the potential beneficial health effects of O_3 pollution in shielding the public from the effects of solar ultraviolet (UV) radiation, as well as adverse health effects. *Id.* at 1051–53. In 1999, the EPA petitioned for rehearing *en banc* on several issues related to that decision. The court granted the request for rehearing in part and denied it in part, but declined to review its ruling with regard to the potential beneficial effects of O_3 pollution. 195 F. 3d 4, 10 (D.C Cir., 1999) (''*ATA II*''). On January 27, 2000, the EPA petitioned the U.S. Supreme Court for *certiorari* on the constitutional issue (and two other issues), but did not request review of the ruling regarding the potential beneficial health effects of O_3. On February 27, 2001, the U.S. Supreme Court unanimously reversed the judgment of the D.C. Circuit on the constitutional issue. *Whitman* v. *American Trucking Assoc.,* 531 U. S. 457, 472–74 (2001) (holding that section 109 of the CAA does not delegate legislative power to the EPA in contravention of the Constitution). The Court remanded the case to the D.C. Circuit to consider challenges to the O_3 NAAQS that had not been addressed by that court's earlier decisions. On March 26, 2002, the D.C. Circuit issued its final decision on remand, finding the 1997 O_3 NAAQS to be ''neither arbitrary nor capricious,'' and so denying the remaining petitions for review. *American Trucking Associations, Inc.* v. *EPA,* 283 F.3d 355, 379 (D.C Cir., 2002) (''*ATA III*'').

Specifically, in *ATA III,* the D.C. Circuit upheld the EPA's decision on the 1997 O_3 standard as the product of reasoned decision making. With regard to the primary standard, the court made clear that the most important support for EPA's decision to revise the standard was the health evidence of insufficient protection afforded by the then-existing standard (''the record is replete with references to studies demonstrating the inadequacies of the old one-hour standard''), as well as extensive information supporting the change to an 8-hour averaging time (283 F. 3d at 378). The court further upheld the EPA's decision not to select a more stringent level for the primary standard noting ''the absence of any human clinical studies at ozone concentrations below 0.08 [ppm]'' which supported the EPA's conclusion that ''the most serious health effects of ozone are 'less certain' at low concentrations, providing an eminently rational reason to set the primary standard at a somewhat higher level, at least until additional studies become available'' (283 F. 3d at 378, internal citations omitted). The court also pointed to the significant weight that the EPA properly placed on the advice it received from CASAC (283 F. 3d at 379). In addition, the court noted that ''although relative proximity to peak background O_3 concentrations did not, in itself, necessitate a level of 0.08 [ppm], the EPA could consider that factor when choosing among the three alternative levels'' (283 F. 3d at 379).

Independently of the litigation, the EPA responded to the court's remand to consider the potential beneficial health effects of O_3 pollution in shielding the public from effects of UV radiation. The EPA provisionally determined that the information linking changes in patterns of ground-level O_3 concentrations to changes in relevant patterns of exposures to UV radiation of concern to public health was too uncertain, at that time, to warrant any relaxation in 1997 O_3 NAAQS. The EPA also expressed the view that any plausible changes in UV–B radiation exposures from changes in patterns of ground-level O_3 concentrations would likely be very small from a public health perspective. In view of these findings, the EPA proposed to leave the 1997 primary standard unchanged (66 FR 57268, Nov. 14, 2001). After considering public comment on the proposed decision, the EPA published its final response to this remand in 2003, re-affirming the 8-hour primary standard set in 1997 (68 FR 614, January 6, 2003).

The EPA initiated the fourth periodic review of the air quality criteria and standards for O_3 with a call for information in September 2000 (65 FR 57810, September, 26, 2000). The schedule for completion of that review was ultimately governed by a consent decree resolving a lawsuit filed in March 2003 by plaintiffs representing national environmental and public health organizations, who maintained that the EPA was in breach of a nondiscretionary duty to complete review of the O_3 NAAQS within a statutorily mandated deadline. In 2007, the EPA proposed to revise the level of the primary standard within a range of 0.075 to 0.070 ppm (72 FR 37818, July 11, 2007). The EPA proposed to revise the secondary standard either by setting it identical to the proposed new primary standard or by setting it as a new seasonal standard using a cumulative form. Documents supporting these proposed decisions included the 2006 AQCD (U.S. EPA, 2006a) and 2007 Staff Paper (U.S. EPA, 2007) and related technical support documents. The EPA completed the review in March 2008 by revising the level of the primary standard from 0.08 ppm to 0.075 ppm, and revising the secondary standard to be identical to the revised primary standard (73 FR 16436, March 27, 2008).

In May 2008, state, public health, environmental, and industry petitioners filed suit challenging the EPA's final decision on the 2008 O_3 standards. On September 16, 2009, the EPA announced its intention to reconsider the 2008 O_3 standards, and initiated a rulemaking to do so. At the EPA's request, the court held the consolidated cases in abeyance pending the EPA's reconsideration of the 2008 decision.

On January 2010, the EPA issued a notice of proposed rulemaking to reconsider the 2008 final decision (75 FR 2938, January 19, 2010). In that notice, the EPA proposed that further revisions of the primary and secondary standards were necessary to provide a requisite level of protection to public health and welfare. The EPA proposed to revise the level of the primary standard from 0.075 ppm to a level within the range of 0.060 to 0.070 ppm, and to revise the secondary standard to one with a cumulative, seasonal form. At the EPA's request, the CASAC reviewed the proposed rule at a public teleconference on January 25, 2010 and provided additional advice in early 2011 (Samet, 2010, 2011). After considering comments from CASAC and the public, the EPA prepared a draft final rule, which was submitted for interagency review pursuant to Executive Order 12866. On September 2, 2011, consistent with the direction of the President, the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), returned the draft final rule to the EPA for further consideration. In view of this return and the fact that the Agency's next periodic review of the O_3 NAAQS required under CAA section 109 had already begun (as announced on September 29, 2008), the EPA decided to consolidate the

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reconsideration with its statutorily required periodic review.[7]

In light of the EPA's decision to consolidate the reconsideration with the current review, the D.C. Circuit proceeded with the litigation on the 2008 final decision. On July 23, 2013, the court upheld the EPA's 2008 primary O_3 standard, but remanded the 2008 secondary standard to the EPA (*Mississippi* v. *EPA,* 744 F. 3d 1334). With respect to the primary standard, the court first held that the EPA reasonably determined that the existing standard was not requisite to protect public health with an adequate margin of safety, and consequently required revision. Specifically, the court noted that there were ''numerous epidemiologic studies linking health effects to exposure to ozone levels below 0.08 ppm and clinical human exposure studies finding a causal relationship between health effects and exposure to ozone levels at and below 0.08 ppm'' (*Mississippi* v. *EPA,* 744 F. 3d at 1345). The court also specifically endorsed the weight of evidence approach utilized by the EPA in its deliberations (*Mississippi* v. *EPA,* 744 F. 3d at 1344).

The court went on to reject arguments that the EPA should have adopted a more stringent primary standard. Dismissing arguments that a clinical study (as properly interpreted by the EPA) showing effects at 0.06 ppm necessitated a standard level lower than that selected, the court noted that this was a single, limited study (*Mississippi* v. *EPA,* 744 F. 3d at 1350). With respect to the epidemiologic evidence, the court accepted the EPA's argument that there could be legitimate uncertainty that a causal relationship between O_3 and 8-hour exposures less than 0.075 ppm exists, so that associations at lower levels reported in epidemiologic studies did not necessitate a more stringent standard (*Mississippi* v. *EPA,* 744 F. 3d at 1351–52).[8]

The court also rejected arguments that an 8-hour primary standard of 0.075 ppm failed to provide an adequate margin of safety, noting that margin of safety considerations involved policy judgments by the agency, and that by setting a standard ''appreciably below'' the level of the current standard (0.08 ppm), the agency had made a reasonable policy choice (*Mississippi* v. *EPA,* 744 F. 3d at 1351–52). Finally, the court rejected arguments that the EPA's decision was inconsistent with the CASAC's scientific recommendations because the CASAC had been insufficiently clear in its recommendations whether it was providing scientific or policy recommendations, and the EPA had reasonably addressed the CASAC's policy recommendations (*Mississippi* v. *EPA,* 744 F. 3d at 1357–58).

With respect to the secondary standard, the court held that the EPA's justification for setting the secondary standard identical to the revised 8-hour primary standard violated the CAA because the EPA had not adequately explained how that standard provided the required public welfare protection. The court thus remanded the secondary standard to the EPA (*Mississippi* v. *EPA,* 744 F. 3d at 1360–62).

At the time of the court's decision, the EPA had already completed significant portions of its next statutorily required periodic review of the O_3 NAAQS. This review was formally initiated in 2008 with a call for information in the **Federal Register** (73 FR 56581, Sept. 29, 2008). On October 28–29, 2008, the EPA held a public workshop to discuss the policy-relevant science, which informed identification of key policy issues and questions to frame the review. Based in part on the workshop discussions, the EPA developed a draft Integrated Review Plan (IRP) outlining the schedule, process,[9] and key policy-relevant questions that would guide the evaluation of the air quality criteria for O_3 and the review of the primary and secondary O_3 NAAQS. A draft of the IRP was released for public review and comment in September 2009 and was the subject of a consultation with the CASAC on November 13, 2009 (74 FR 54562; October 22, 2009).[10] After considering the comments received from that consultation and from the public, the EPA completed and released the IRP for the review in 2011 (U.S. EPA, 2011a).

In preparing the first draft ISA, the EPA's National Center for Environmental Assessment (NCEA) considered CASAC and public comments on the IRP, and also comments received from a workshop held on August 6, 2010, to review and discuss preliminary drafts of key ISA sections (75 FR 42085, July 20, 2010). In 2011, the first draft ISA was released for public comment and for review by CASAC at a public meeting on May 19–20, 2011 (U.S. EPA, 2011b; 76 FR 10893, February 28, 2011; 76 FR 23809, April 28, 2011). Based on CASAC and public comments, NCEA prepared a second draft ISA, which was released for public comment and CASAC review (U.S. EPA, 2011c; 76 FR 60820, September 30, 2011). The CASAC reviewed this draft at a January 9–10, 2012, public meeting (76 FR 236, December 8, 2011). Based on CASAC and public comments, NCEA prepared a third draft ISA (U.S. EPA, 2012; 77 FR 36534, June 19, 2012), which was reviewed at a CASAC meeting in September 2012. The EPA released the final ISA in February 2013 (U.S. EPA, 2013).

The EPA presented its plans for conducting Risk and Exposure Assessments (REAs) for health risk and exposure (HREA) and welfare risk and exposure (WREA) in two documents that outlined the scope and approaches for use in conducting quantitative assessments, as well as key issues to be addressed as part of the assessments (U.S. EPA, 2011d, e). The EPA released these documents for public comment in April 2011, and consulted with CASAC on May 19–20, 2011 (76 FR 23809, April 28, 2011). The EPA considered CASAC advice and public comments in further planning for the assessments, issuing a memo that described changes to elements of the REA plans and brief explanations regarding them (Samet, 2011; Wegman, 2012).

In July 2012, the EPA made the first drafts of the Health and Welfare REAs available for CASAC review and public comment (77 FR 42495, July 19, 2012; 77 FR 51798, August 27, 2012). The first draft PA was made available for CASAC review and public comment in August 2012 (77 FR 42495, July 19, 2012; 77 FR 51798, August 27, 2012).[11] The first

[7] This rulemaking concludes the reconsideration process. Under CAA section 109, the EPA is required to base its review of the NAAQS on the current air quality criteria, and thus the record and decision for this review also serve for the reconsideration.

[8] The court cautioned, however, that ''perhaps more [clinical] studies like the Adams studies will yet reveal that the 0.060 ppm level produces significant adverse decrements that simply cannot be attributed to normal variation in lung function,'' and further cautioned that ''agencies may not merely recite the terms 'substantial uncertainty' as a justification for their actions.'' *Id.* at 1350, 1357 (internal citations omitted).

[9] As of this review, the document developed in NAAQS reviews to document the air quality criteria, previously the AQCD, is the ISA, and the document describing the OAQPS staff evaluation, previously the Staff Paper, is the PA. These documents are described in the IRP.

[10] See *http://yosemite.epa.gov/sab/sabproduct.nsf/WebProjectsbyTopicCASAC!OpenView* for more information on CASAC activities related to the current O_3 NAAQS review.

[11] The PA is prepared by the OAQPS staff. Formerly known as the Staff Paper, it presents a staff evaluation of the policy implications of the key scientific and technical information in the ISA and REAs for the EPA's consideration. The PA provides a transparent evaluation, and staff conclusions, regarding policy considerations related to reaching judgments about the adequacy of the current standards, and if revision is considered, what revisions may be appropriate to consider. The PA is intended to help ''bridge the gap'' between the agency's scientific assessments presented in the ISA

draft REAs and PA were the focus of a CASAC public meeting in September 2012 (Frey and Samet, 2012a, 2012b). The second draft REAs and PA, prepared with consideration of CASAC advice and public comments, were made available for public comment and CASAC review in January 2014 (79 FR 4694, January 29, 2014). These documents were the focus of a CASAC public meeting on March 25–27, 2014 (Frey, 2014a; Frey, 2014b; Frey, 2014c). The final versions of these documents were developed with consideration of the comments and recommendations from CASAC, as well as comments from the public on the draft documents, and were released in August 2014 (U.S. EPA 2014a; U.S. EPA, 2014b; U.S. EPA, 2014c).

The proposed decision (henceforth ''proposal'') on this review of the O_3 NAAQS was signed on November 25, 2014, and published in the **Federal Register** on December 17, 2014. The EPA held three public hearings to provide direct opportunity for oral testimony by the public on the proposal. The hearings were held on January 29, 2015, in Arlington, Texas, and Washington, DC, and on February 2, 2015, in Sacramento, California. At these public hearings, the EPA heard testimony from nearly 500 individuals representing themselves or specific interested organizations. Transcripts from these hearings and written testimony provided at the hearings are in the docket for this review. Additionally, approximately 430,000 written comments were received from various commenters during the public comment period on the proposal, approximately 428,000 as part of mass mail campaigns. Significant issues raised in the public comments are discussed in the preamble of this final action. A summary of all other significant comments, along with the EPA's responses, can be found in a separate document (henceforth ''Response to Comments'') in the docket for this review.

The schedule for completion of this review is governed by a court order resolving a lawsuit filed in January 2014 by a group of plaintiffs who alleged that the EPA had failed to perform its mandatory duty, under section 109(d)(1), to complete a review of the O_3 NAAQS within the period provided by statute. The court order that governs this review, entered by the court on April 30, 2014, provides that the EPA will sign for publication a notice of final rulemaking concerning its review of the O_3 NAAQS no later than October 1, 2015.

As in prior NAAQS reviews, the EPA is basing its decision in this review on studies and related information included in the ISA, REAs and PA, which have undergone CASAC and public review. The studies assessed in the ISA and PA, and the integration of the scientific evidence presented in them, have undergone extensive critical review by the EPA, the CASAC, and the public. The rigor of that review makes these studies, and their integrative assessment, the most reliable source of scientific information on which to base decisions on the NAAQS, decisions that all parties recognize as of great import. NAAQS decisions can have profound impacts on public health and welfare, and NAAQS decisions should be based on studies that have been rigorously assessed in an integrative manner not only by the EPA but also by the statutorily mandated independent advisory committee, as well as the public review that accompanies this process. Some commenters have referred to and discussed individual scientific studies on the health and welfare effects of O_3 that were not included in the ISA (USEPA, 2013) ('' 'new' studies''). In considering and responding to comments for which such ''new'' studies were cited in support, the EPA has provisionally considered the cited studies in the context of the findings of the ISA. The EPA's provisional consideration of these studies did not and could not provide the kind of in-depth critical review described above.

The decision to rely on studies and related information included in the ISA, REAs and PA, which have undergone CASAC and public review, is consistent with the EPA's practice in prior NAAQS reviews and its interpretation of the requirements of the CAA. Since the 1970 amendments, the EPA has taken the view that NAAQS decisions are to be based on scientific studies and related information that have been assessed as a part of the pertinent air quality criteria, and the EPA has consistently followed this approach. This longstanding interpretation was strengthened by new legislative requirements enacted in 1977, which added section 109(d)(2) of the Act concerning CASAC review of air quality criteria. See 71 FR 61144, 61148 (October 17, 2006) (final decision on review of NAAQS for particulate matter) for a detailed discussion of this issue and the EPA's past practice.

As discussed in the EPA's 1993 decision not to revise the NAAQS for O_3, ''new'' studies may sometimes be of such significance that it is appropriate to delay a decision on revision of a NAAQS and to supplement the pertinent air quality criteria so the studies can be taken into account (58 FR at 13013–13014, March 9, 1993). In the present case, the EPA's provisional consideration of ''new'' studies concludes that, taken in context, the ''new'' information and findings do not materially change any of the broad scientific conclusions regarding the health and welfare effects and exposure pathways of ambient O_3 made in the air quality criteria. For this reason, reopening the air quality criteria review would not be warranted even if there were time to do so under the court order governing the schedule for this rulemaking.

Accordingly, the EPA is basing the final decisions in this review on the studies and related information included in the O_3 air quality criteria that have undergone CASAC and public review. The EPA will consider the ''new'' studies for purposes of decision making in the next periodic review of the O_3 NAAQS, which the EPA expects to begin soon after the conclusion of this review and which will provide the opportunity to fully assess these studies through a more rigorous review process involving the EPA, CASAC, and the public. Further discussion of these ''new'' studies can be found in the Response to Comments document, which is in the docket for this rulemaking and also available on the web (*http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*).

D. Ozone Air Quality

Ozone is formed near the earth's surface due to chemical interactions involving solar radiation and precursor pollutants including volatile organic compounds (VOCs) and NO_X. Over longer time periods, methane (CH_4) and carbon monoxide (CO) can also lead to O_3 formation at the global scale. The precursor emissions leading to O_3 formation can result from both man-made sources (*e.g.,* motor vehicles and electric power generation) and natural sources (*e.g.,* vegetation and wildfires). Occasionally, O_3 that is created naturally in the stratosphere can also contribute to O_3 levels near the surface. Once formed, O_3 near the surface can be transported by winds before eventually being removed from the atmosphere via chemical reactions or deposition to surfaces. In sum, O_3 concentrations are influenced by complex interactions between precursor emissions, meteorological conditions, and surface characteristics (U.S. EPA, 2014a).

and REAs, and the judgments required of the EPA Administrator in determining whether it is appropriate to retain or revise the NAAQS.

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In order to continuously assess O_3 air pollution levels, state and local environmental agencies operate O_3 monitors at various locations and subsequently submit the data to the EPA. At present, there are approximately 1,400 monitors across the U.S. reporting hourly O_3 averages during the times of the year when local O_3 pollution can be important (U.S. EPA, 2014c, Section 2.1). Much of this monitoring is focused on urban areas where precursor emissions tend to be largest, as well as locations directly downwind of these areas, but there are also over 100 sites in rural areas where high levels of O_3 can also be measured. Based on data from this national network, the EPA estimates that, in 2013, approximately 99 million Americans lived in counties where O_3 design values [12] were above the level of the existing health-based (primary) NAAQS of 0.075 ppm. High O_3 values can occur almost anywhere within the contiguous 48 states, although the poorest O_3 air quality in the U.S. is typically observed in California, Texas, and the Northeast Corridor, locations with some of the most densely populated areas in the country. From a temporal perspective, the highest daily peak O_3 concentrations generally tend to occur during the afternoon within the warmer months due to higher solar radiation and other conducive meteorological conditions during these times. The exceptions to this general rule include 1) some rural sites where transport of O_3 from upwind areas of regional production can occasionally result in high nighttime levels of O_3, 2) high-elevation sites episodically influenced by stratospheric intrusions which can occur in other months, and 3) certain locations in the western U.S. where large quantities of O_3 precursors emissions associated with oil and gas development can be trapped by strong inversions associated with snow cover during the colder months and efficiently converted to O_3 (U.S. EPA, 2014c, Section 2.3).

One of the challenging aspects of developing plans to address high O_3 concentrations is that the response of O_3 to precursor reductions is nonlinear. In particular, NO_X emissions can lead to both increases and decreases of O_3. The net impact of NO_X emissions on O_3 concentrations depends on the local quantities of NO_X, VOC, and sunlight which interact in a set of complex chemical reactions. In some areas, such as certain urban centers where NO_X emissions typically are high compared to local VOC emissions, NO_X can suppress O_3 locally. This phenomenon is particularly pronounced under conditions associated with low O_3 concentrations (*i.e.,* during cool, cloudy weather and at night when photochemical activity is limited or nonexistent). However, while NO_X emissions can initially suppress O_3 levels near the emission sources, these same NO_X emissions ultimately react to form higher O_3 levels downwind when conditions are favorable. Photochemical model simulations suggest that, in general, reductions in NO_X emissions in the U.S. will slightly increase O_3 concentrations on days with lower O_3 concentrations in close proximity to NO_X sources (*e.g.,* in urban core areas), while at the same time decreasing the highest O_3 concentrations in downwind areas. See generally, U.S. EPA, 2014a (section 2.2.1).

At present, both the primary and secondary NAAQS use the annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years, as the form of the standard. An additional metric, the W126 exposure index, is often used to assess impacts of O_3 exposure on ecosystems and vegetation. W126 is a cumulative seasonal aggregate of weighted hourly O_3 values observed between 8 a.m. and 8 p.m. As O_3 precursor emissions have decreased across the U.S., annual fourth-highest 8-hour O_3 maxima have concurrently shown a modest downward trend. The national average change in annual fourth-highest daily maximum 8-hour O_3 concentrations between 2000 and 2013 was an 18% decrease. The national average change in the annual W126 exposure index over the same period was a 52% decrease. Air quality model simulations estimate that O_3 air quality will continue to improve over the next decade as additional reductions in O_3 precursors from power plants, motor vehicles, and other sources are realized.

In addition to being affected by changing emissions, future O_3 concentrations may also be affected by climate change. Modeling studies in the EPA's Interim Assessment (U.S. EPA, 2009a) that are cited in support of the 2009 Endangerment Finding under CAA section 202(a) (74 FR 66496, Dec. 15, 2009) as well as a recent assessment of potential climate change impacts (Fann et al., 2015) project that climate change may lead to future increases in summer O_3 concentrations across the contiguous U.S.[13] While the projected impact is not uniform, climate change has the potential to increase average summertime O_3 concentrations by as much as 1–5 ppb by 2030, if greenhouse gas emissions are not mitigated. Increases in temperature are expected to be the principal factor in driving any O_3 increases, although increases in stagnation frequency may also contribute (Jacob and Winner, 2009). If unchecked, climate change has the potential to offset some of the improvements in O_3 air quality, and therefore some of the improvements in public health, that are expected from reductions in emissions of O_3 precursors.

Another challenging aspect of this air quality issue is the impact from sources of O_3 and its precursors beyond those from domestic, anthropogenic sources. Modeling analyses indicate that nationally the majority of O_3 exceedances are predominantly caused by anthropogenic emissions from within the U.S. However, observational and modeling analyses have concluded that O_3 concentrations in some locations in the U.S. on some days can be substantially influenced by sources that cannot be addressed by domestic control measures. In particular, certain high-elevation sites in the western U.S. are impacted by a combination of non-U.S. sources like international transport, or natural sources such as stratospheric O_3, and O_3 originating from wildfire emissions.[14] Ambient O_3 from these non-U.S. and natural sources is collectively referred to as background O_3. See generally section 2.4 of the PA (U.S. EPA, 2014c). The analyses suggest that, at these locations, there can be episodic events with substantial background contributions where O_3 concentrations approach or exceed the level of the current NAAQS (*i.e.,* 75 ppb). These events are relatively infrequent, and the EPA has policies that allow for the exclusion of air quality monitoring data from design value calculations when they are substantially affected by certain background influences.

E. Summary of Proposed Revisions to the O_3 Standards

For reasons discussed in the proposal, the Administrator proposed to revise the

[12] A design value is a statistic that describes the air quality status of a given location relative to the level of the NAAQS.

[13] These modeling studies are based on coupled global climate and regional air quality models and are designed to assess the sensitivity of U.S. air quality to climate change. A wide range of future climate scenarios and future years have been modeled and there can be variations in the expected response in U.S. O_3 by scenario and across models and years, within the overall signal of higher summer O_3 concentrations in a warmer climate.

[14] Without global greenhouse gas mitigation efforts, climate change is projected to dramatically increase the area burned by wildfires across most of the contiguous U.S., especially in the West (U.S. EPA, 2015 p. 72).

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current primary and secondary standards for O_3. With regard to the primary standard, the Administrator proposed to revise the level from 75 ppb to a level within a range from 65 to 70 ppb. The EPA proposed to revise the AQI for O_3, consistent with revision to the primary standard.

With regard to the secondary standard, the Administrator proposed to revise the level of the current secondary standard to within the range of 0.065 to 0.070 ppm, which air quality analyses indicate would provide cumulative, seasonal air quality or exposure values, in terms of 3-year average W126 index values, at or below a range of 13–17 ppm-hours.

The EPA also proposed to make corresponding revisions in data handling conventions for O_3; to revise regulations for the PSD permitting program to add a provision grandfathering certain pending permits from certain requirements with respect to the proposed revisions to the standards; and to convey schedules and information related to implementing any revised standards. In conjunction with proposing exceptional event schedules related to implementing any revised O_3 standards, the EPA also proposed to extend the new schedule approach to other future NAAQS revisions and to remove obsolete regulatory language associated with expired exceptional event deadlines for historical standards for both O_3 and other pollutants for which NAAQS have been established. The EPA also proposed to make minor changes to the procedures and time periods for evaluating potential FRMs and equivalent methods, including making the requirements for NO_2 consistent with the requirements for O_3, and removing an obsolete requirement for the annual submission of documentation by manufacturers of certain particulate matter monitors.

F. Organization and Approach to Decisions in This O_3 NAAQS Review

This action presents the Administrator's final decisions in the current review of the primary and secondary O_3 standards. The final decisions addressing standards for O_3 are based on a thorough review in the ISA of scientific information on known and potential human health and welfare effects associated with exposure to O_3 at levels typically found in the ambient air. These final decisions also take into account the following: (1) Staff assessments in the PA of the most policy-relevant information in the ISA as well as a quantitative health and welfare exposure and risk assessments based on that information; (2) CASAC advice and recommendations, as reflected in its letters to the Administrator and its discussions of drafts of the ISA, REAs, and PA at public meetings; (3) public comments received during the development of these documents, both in connection with CASAC meetings and separately; and (4) extensive public comments received on the proposed rulemaking.

The primary standard is addressed in section II. Corresponding changes to the AQI are addressed in section III. The secondary standard is addressed in section IV. Related data handling conventions and exceptional events are addressed in section V. Updates to the monitoring regulations are addressed in section VI. Implementation activities, including PSD-related actions, are addressed in sections VII and VIII. Section IX addresses applicable statutory and executive order reviews.

II. Rationale for Decision on the Primary Standard

This section presents the Administrator's final decisions regarding the need to revise the existing primary O_3 standard and the appropriate revision to the level of that standard. Based on her consideration of the full body of health effects evidence and exposure/risk analyses, the Administrator concludes that the current primary standard for O_3 is not requisite to protect public health with an adequate margin of safety. In order to increase public health protection, she is revising the level of the primary standard to 70 ppb, in conjunction with retaining the current indicator, averaging time and form. The Administrator concludes that such a revised standard will be requisite to protect public health with an adequate margin of safety. As discussed more fully below, the rationale for these final decisions draws from the thorough review in the ISA (U.S. EPA, 2013) of the available scientific evidence, generally published through July 2011, on human health effects associated with the presence of O_3 in the ambient air. This rationale also takes into account: (1) Analyses of O_3 air quality, human exposures to O_3, and O_3-associated health risks, as presented and assessed in the HREA (U.S. EPA, 2014a); (2) the EPA staff assessment of the most policy-relevant scientific evidence and exposure/risk information in the PA (U.S. EPA, 2014c); (3) CASAC advice and recommendations, as reflected in discussions of drafts of the ISA, REA, and PA at public meetings, in separate written comments, and in CASAC's letters to the Administrator; (4) public input received during the development of these documents, either in connection with CASAC meetings or separately; and (5) public comments on the proposal notice.

Section II.A below summarizes the information presented in the proposal regarding O_3-associated health effects, O_3 exposures, and O_3-attributable health risks. Section II.B presents information related to the adequacy of the current primary O_3 standard, including a summary of the basis for the Administrator's proposed decision to revise the current standard, public comments received on the adequacy of the current standard, and the Administrator's final conclusions regarding the adequacy of the current standard. Section II.C presents information related to the elements of a revised primary O_3 standard, including information related to each of the major elements of the standard (*i.e.,* indicator, averaging time, form, level). Section II.D summarizes the Administrator's final decisions on the primary O_3 standard.

A. Introduction

As discussed in section II.A of the proposal (79 FR 75243–75246, December 17, 2014), the EPA's approach to informing decisions on the primary O_3 standard in the current review builds upon the general approaches used in previous reviews and reflects the broader body of scientific evidence, updated exposure/risk information, and advances in O_3 air quality modeling now available. This approach is based most fundamentally on using the EPA's assessment of the available scientific evidence and associated quantitative analyses to inform the Administrator's judgments regarding a primary standard for O_3 that is ''requisite'' (*i.e.,* neither more nor less stringent than necessary) to protect public health with an adequate margin of safety. Specifically, it is based on consideration of the available body of scientific evidence assessed in the ISA (U.S. EPA, 2013), exposure and risk analyses presented in the HREA (U.S. EPA, 2014a), evidence- and exposure-/risk-based considerations and conclusions presented in the PA (U.S. EPA, 2014c), advice and recommendations received from CASAC (Frey, 2014a, c), and public comments.

Section II.A.1 below summarizes the information presented in the proposal regarding O_3-associated health effects. Section II.A.2 summarizes the information presented in the proposal regarding O_3 exposures and O_3-attributable health risks.

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1. Overview of Health Effects Evidence

The health effects of O_3 are described in detail in the ISA (U.S. EPA, 2013). Based on its assessment of the health effects evidence, the ISA determined that a ''causal'' relationship exists between short-term exposure to O_3 in ambient air and effects on the respiratory system [15] and that a ''likely to be causal'' relationship exists between long-term exposure to O_3 in ambient air and respiratory effects [16] (U.S. EPA, 2013, pp. 1–6 to 1–7). The ISA summarizes the longstanding body of evidence for O_3 respiratory effects as follows (U.S. EPA, 2013, p. 1–5):

> The clearest evidence for health effects associated with exposure to O_3 is provided by studies of respiratory effects. Collectively, a very large amount of evidence spanning several decades supports a relationship between exposure to O_3 and a broad range of respiratory effects (see Section 6.2.9 and Section 7.2.8). The majority of this evidence is derived from studies investigating short-term exposures (*i.e.,* hours to weeks) to O_3, although animal toxicological studies and recent epidemiologic evidence demonstrate that long-term exposure (*i.e.,* months to years) may also harm the respiratory system.

Additionally, the ISA determined that the relationships between short-term exposures to O_3 in ambient air and both total mortality and cardiovascular effects are likely to be causal, based on expanded evidence bases in the current review (U.S. EPA, 2013, pp. 1–7 to 1–8). The ISA determined that the currently available evidence for additional endpoints is ''suggestive'' of causal relationships with short-term (central nervous system effects) and long-term exposures (cardiovascular effects, reproductive and developmental effects, central nervous system effects and total mortality) to ambient O_3.

Consistent with emphasis in past reviews on O_3 health effects for which the evidence is strongest, in this review the EPA places the greatest emphasis on studies of health effects that have been determined in the ISA to be caused by, or likely to be caused by, O_3 exposures (U.S. EPA, 2013, section 2.5.2). This preamble section summarizes the evidence for health effects attributable to O_3 exposures, with a focus on respiratory morbidity and mortality effects attributable to short- and long-term exposures, and cardiovascular system effects (including mortality) and total mortality attributable to short-term exposures (from section II.B in the proposal, 79 FR 75246–75271).

The information highlighted here is based on the assessment of the evidence in the ISA (U.S. EPA, 2013, Chapters 4 to 8) and consideration of that evidence in the PA (U.S. EPA, 2014c, Chapters 3 and 4) on the known or potential effects on public health which may be expected from the presence of O_3 in the ambient air. This section summarizes: (1) Information available on potential mechanisms for health effects associated with exposure to O_3 (II.A.1.a); (2) the nature of effects that have been associated directly with both short- and long-term exposure to O_3 and indirectly with the presence of O_3 in ambient air (II.A.1.b); (3) considerations related to the adversity of O_3-attributable health effects (II.A.1.c); and (4) considerations in characterizing the public health impact of O_3, including the identification of ''at risk'' populations (II.A.1.d).

a. Overview of Mechanisms

This section briefly summarizes the characterization of the key events and pathways that contribute to health effects resulting from O_3 exposures, as discussed in the proposal (79 FR 75247, section II.B.1) and in the ISA (U.S. EPA, 2013, section 5.3).

Experimental evidence elucidating modes of action and/or mechanisms contributes to our understanding of the biological plausibility of adverse O_3-related health effects, including respiratory effects and effects outside the respiratory system (U.S. EPA, 2013, Chapters 6 and 7). Evidence indicates that the initial key event is the formation of secondary oxidation products in the respiratory tract (U.S. EPA, 2013, section 5.3). This mainly involves direct reactions with components of the extracellular lining fluid (ELF). Although the ELF has inherent capacity to quench (based on individual antioxidant capacity), this capacity can be overwhelmed, especially with exposure to elevated concentrations of O_3 (U.S. EPA 2014c, at 3–3, 3–9). The resulting secondary oxidation products transmit signals to the epithelium, pain receptive nerve fibers and, if present, immune cells involved in allergic responses. The available evidence indicates that the effects of O_3 are mediated by components of ELF and by the multiple cell types in the respiratory tract. Oxidative stress is an implicit part of this initial key event.

Secondary oxidation products initiate numerous responses at the cellular, tissue, and whole organ level of the respiratory system. These responses include the activation of neural reflexes which leads to lung function decrements; initiation of pulmonary inflammation; alteration of barrier epithelial function; sensitization of bronchial smooth muscle; modification of lung host defenses; airways remodeling; and modulation of autonomic nervous function which may alter cardiac function (U.S. EPA, 2013, section 5.3, Figure 5–8).

Persistent inflammation and injury, which are observed in animal models of chronic and quasi-continuous exposure to O_3, are associated with airways remodeling (see section 7.2.3 of the ISA, U.S. EPA, 2013). Chronic quasi-continuous exposure to O_3 has also been shown to result in effects on the developing lung and immune system. Systemic inflammation and vascular oxidative/nitrosative stress are also key events in the toxicity pathway of O_3 (U.S. EPA, 2013, section 5.3.8). Extrapulmonary effects of O_3 occur in numerous organ systems, including the cardiovascular, central nervous, reproductive, and hepatic systems (U.S. EPA, 2013, sections 6.3 to 6.5 and sections 7.3 to 7.5).

Responses to O_3 exposure are variable within the population. Studies have shown a large range of pulmonary function (*i.e.,* spirometric) responses to O_3 among healthy young adults, while responses within an individual are relatively consistent over time. Other responses to O_3 have also been characterized by a large degree of interindividual variability, including airways inflammation. The mechanisms that may underlie the variability in responses seen among individuals are discussed in the ISA (U.S. EPA, 2013, section 5.4.2). Certain functional genetic polymorphisms, pre-existing conditions or diseases, nutritional status, lifestages, and co-exposures can contribute to altered risk of O_3-induced effects. Experimental evidence for such O_3-induced changes contributes to our understanding of the biological plausibility of adverse O_3-related health effects, including a range of respiratory effects as well as effects outside the respiratory system (*e.g.,* cardiovascular effects) (U.S. EPA, 2013, Chapters 6 and 7).

b. Nature of Effects

This section briefly summarizes the information presented in the proposal on respiratory effects attributable to short-term exposures (II.A.1.b.i), respiratory effects attributable to long-

[15] In determining that a causal relationship exists for O_3 with specific health effects, the EPA has concluded that ''[e]vidence is sufficient to conclude that there is a causal relationship with relevant pollutant exposures'' (U.S. EPA, 2013, p. lxiv).

[16] In determining a ''likely to be a causal'' relationship exists for O_3 with specific health effects, the EPA has concluded that ''[e]vidence is sufficient to conclude that a causal relationship is likely to exist with relevant pollutant exposures, but important uncertainties remain'' (U.S. EPA, 2013, p. lxiv).

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term exposures (II.A.1.b.ii), cardiovascular effects attributable to short-term exposures (II.A.1.b.iii), and premature mortality attributable to short-term exposures (II.A.1.b.iv) (79 FR 75247, section II.B.2).

i. Respiratory Effects—Short-term Exposure

Controlled human exposure, animal toxicological, and epidemiologic studies available in the last review provided clear, consistent evidence of a causal relationship between short-term O_3 exposure and respiratory effects (U.S. EPA, 2006a). Recent studies evaluated since the completion of the 2006 AQCD support and expand upon the strong body of evidence available in the last review (U.S. EPA, 2013, section 6.2.9).

Key aspects of this evidence are discussed below with regard to (1) lung function decrements; (2) pulmonary inflammation, injury, and oxidative stress; (3) airway hyperresponsiveness; (4) respiratory symptoms and medication use; (5) lung host defense; (6) allergic and asthma-related responses; (7) hospital admissions and emergency department visits; and (8) respiratory mortality.[17]

Lung Function Decrements

Lung function decrements are typically measured by spirometry and refer to reductions in the maximal amount of air that can be forcefully exhaled. Forced expiratory volume in 1 second (FEV_1) is a common index used to assess the effect of O_3 on lung function. The ISA summarizes the currently available evidence from multiple controlled human exposure studies evaluating changes in FEV_1 following 6.6-hour O_3 exposures in young, healthy adults engaged in moderate levels of physical activity [18] (U.S. EPA, 2013, section 6.2.1.1, Figure 6–1). Exposures to an average O_3 concentration of 60 ppb results in group mean decrements in FEV_1 ranging from 1.8% to 3.6% (Adams, 2002; Adams, 2006; [19] Schelegle et al., 2009; [20] Kim et al., 2011). The weighted average group mean decrement was 2.7% from these studies. In some analyses, these group mean decrements in lung function were statistically significant (Brown et al., 2008; Kim et al., 2011), while in other analyses they were not (Adams, 2006; Schelegle et al., 2009).[21] Prolonged exposure to an average O_3 concentration of 72 ppb results in a statistically significant group mean decrement in FEV_1 of about 6% (Schelegle et al., 2009).[22] There is a smooth dose-response curve without evidence of a threshold for exposures between 40 and 120 ppb O_3 (U.S. EPA, 2013, Figure 6–1). When these data are taken together, the ISA concludes that ''mean FEV_1 is clearly decreased by 6.6-hour exposures to 60 ppb O_3 and higher concentrations in [healthy, young adult] subjects performing moderate exercise'' (U.S. EPA, 2013, p. 6–9).

As described in the proposal (79 FR 75250), the ISA focuses on individuals with >10% decrements in FEV_1 because (1) it is accepted by the American Thoracic Society (ATS) as an abnormal response and a reasonable criterion for assessing exercise-induced bronchoconstriction, and (2) some individuals in the Schelegle et al. (2009) study experienced 5–10% FEV_1 decrements following exposure to filtered air. The proportion of healthy adults experiencing FEV_1 decrements >10% following prolonged exposures to 80 ppb O_3 while at moderate exertion ranged from 17% to 29% and following exposures to 60 ppb O_3 ranged from 3% to 20%. The weighted average proportion (*i.e.,* based on numbers of subjects in each study) of young, healthy adults with >10% FEV_1 decrements is 25% following exposure to 80 ppb O_3 and 10% following exposure to 60 ppb O_3, for 6.6 hours at moderate exertion (U.S. EPA, 2013, page 6–18 and 6–19).[23] Responses within an individual tend to be reproducible over a period of several months, reflecting differences in intrinsic responsiveness. Given this, the ISA concludes that ''[t]hough group mean decrements are biologically small and generally do not attain statistical significance, a considerable fraction of exposed individuals [in the clinical studies] experience clinically meaningful decrements in lung function'' when exposed for 6.6 hours to 60 ppb O_3 during quasi-continuous, moderate exertion (U.S. EPA, 2013, section 6.2.1.1, p. 6–20).

This review has marked an advance in the ability to make reliable quantitative predictions of the potential lung function response to O_3 exposure, and, thus, to reasonably predict the degree of interindividual response of lung function to that exposure. McDonnell et al. (2012) and Schelegle et al. (2012) developed models, described in more detail in the proposal (79 FR 75250), that included mathematical approaches to simulate the potential protective effect of antioxidants in the ELF at lower ambient O_3 concentrations, and that included a dose threshold below which changes in lung function do not occur. The resulting empirical models can estimate the frequency distribution of individual responses and summary measures of the distribution such as the mean or median response and the proportions of individuals with FEV_1 decrements >10%, 15%, and 20%.[24] The predictions of the models are consistent with the observed results from the individual controlled human exposure studies of O_3-induced FEV_1 decrements (79 FR 75250–51, see also U.S. EPA, 2013, Figures 6–1 and 6–3). CASAC agreed that these models mark a significant technical advance over the exposure-response modeling approach used for the lung function risk assessment in the last review and explicitly found that ''[t]he MSS model to be scientifically and biologically defensible'' (Frey, 2014a, pp. 8, 2). CASAC also stated that ''the comparison of the MSS model results to those obtained with the exposure-response model is of tremendous importance. Typically, the MSS model gives a result about a factor of three higher . . . for school-age children, which is expected because the MSS model includes

[17] CASAC concurred that these were ''the kinds of identifiable effects on public health that are expected from the presence of ozone in the ambient air'' (Frey 2014c, p. 3).

[18] Table 6–1 of the ISA includes descriptions of the activity levels evaluated in controlled human exposure studies (U.S. EPA, 2013).

[19] Adams (2006); (2002) both provide data for an additional group of 30 healthy subjects that were exposed via facemask to 60 ppb O_3 for 6.6 hours with moderate exercise. These subjects are described on page 133 of Adams (2006) and pages 747 and 761 of Adams (2002). The facemask exposure is not expected to affect the FEV_1 responses relative to a chamber exposure.

[20] For the 60 ppb target exposure concentration, Schelegle et al. (2009) reported that the actual mean exposure concentration was 63 ppb.

[21] Adams (2006) did not find effects on FEV_1 at 60 ppb to be statistically significant. In an analysis of the Adams (2006) data, Brown et al. (2008) addressed the more fundamental question of whether there were statistically significant differences in responses before and after the 6.6 hour exposure period and found the average effect on FEV_1 at 60 ppb to be small, but highly statistically significant using several common statistical tests, even after removal of potential outliers. Schelegle et al. (2009) reported that, compared to filtered air, the largest change in FEV_1 for the 60 ppb protocol occurred after the sixth (and final) exercise period.

[22] As noted above, for the 70 ppb exposure group, Schelegle et al. (2009) reported that the actual mean exposure concentration was 72 ppb.

[23] The ISA notes that by considering responses uncorrected for filtered air exposures, during which lung function typically improves (which would increase the size of the change, pre-and post-exposure), 10% is an underestimate of the proportion of healthy individuals that are likely to experience clinically meaningful changes in lung function following exposure for 6.6 hours to 60 ppb O_3 during quasi-continuous moderate exertion (U.S. EPA, 2012, section 6.2.1.1).

[24] One of these models, the McDonnell-Stewart-Smith (MSS) model (McDonnell et al. 2012) was used to estimate the occurrences of lung function decrements in the HREA.

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responses for a wider range of exposure protocols'' (Frey, 2014a, pp. 8, 2).

Epidemiologic studies have consistently linked short-term increases in ambient O_3 concentrations with lung function decrements in diverse populations and lifestages, including children attending summer camps, adults exercising or working outdoors, and groups with pre-existing respiratory diseases such as asthmatic children (U.S. EPA, 2013, section 6.2.1.2). Some of these studies reported O_3-associated lung function decrements accompanied by respiratory symptoms[25] in asthmatic children. In contrast, studies of children in the general population have reported similar O_3-associated lung function decrements but without accompanying respiratory symptoms (79 FR 75251; U.S. EPA, 2013, section 6.2.1.2). As noted in the PA (EPA, 2014c, pp. 4–70 to 4–71), additional research is needed to evaluate responses of people with asthma and healthy people in the 40 to 70 ppb range. Further epidemiologic studies and meta-analyses of the effects of O_3 exposure on children will help elucidate the concentration-response functions for lung function and respiratory symptom effects at lower O_3 concentrations.

Several epidemiologic panel studies[26] reported statistically significant associations with lung function decrements at relatively low ambient O_3 concentrations. For outdoor recreation or exercise, associations were reported in analyses restricted to 1-hour average O_3 concentrations less than 80 ppb, down to less than 50 ppb. Among outdoor workers, Brauer et al. (1996) found a robust association with daily 1-hour max O_3 concentrations less than 40 ppb. Ulmer et al. (1997) found a robust association in schoolchildren with 30-minute maximum O_3 concentrations less than 60 ppb. For 8-hour average O_3 concentrations, associations with lung function decrements in children with asthma were found to persist at concentrations less than 80 ppb in a U.S. multicity study (Mortimer et al., 2002) and less than 51 ppb in a study conducted in the Netherlands (Gielen et al., 1997).

As described in the proposal (79 FR 75251), several epidemiologic panel studies provided information on potential confounding by copollutants and most O_3 effect estimates for lung function were robust to adjustment for temperature, humidity, and copollutants such as particulate matter with mass median aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$), particulate matter with mass median aerodynamic diameter less than or equal to 10 micrometers (PM_{10}), NO_2, or sulfur dioxide (SO_2) (Hoppe et al., 2003; Brunekreef et al., 1994; Hoek et al. 1993; U.S. EPA, 2013, pp. 6–67 to 6–69). Although examined in only a few epidemiologic studies, O_3 also remained associated with decreases in lung function with adjustment for pollen or acid aerosols (79 F 75251; U.S. EPA, 2013, section 6.2.1.2).

Pulmonary Inflammation, Injury and Oxidative Stress

As described in detail in section II.B.2.a.ii of the proposal (79 FR 75252), O_3 exposures can result in increased respiratory tract inflammation and epithelial permeability. Inflammation is a host response to injury, and the induction of inflammation is evidence that injury has occurred. Oxidative stress has been shown to play a key role in initiating and sustaining O_3-induced inflammation. As noted in the ISA (U.S. EPA, 2013, section 6.2.3), O_3 exposures can initiate an acute inflammatory response throughout the respiratory tract that has been reported to persist for at least 18–24 hours after exposure.

Inflammation induced by exposure of humans to O_3 can have several potential outcomes, ranging from resolving entirely following a single exposure to becoming a chronic inflammatory state, as described in detail in section II.B.2.a.ii of the proposal (79 FR 75252) and in the ISA (U.S. EPA, 2013, section 6.2.3). Continued cellular damage due to chronic inflammation ''may alter the structure and function of pulmonary tissues'' (U.S. EPA, 2013, p. 6–161). Lung injury and the resulting inflammation provide a mechanism by which O_3 may cause other more serious morbidity effects (*e.g.,* asthma exacerbations) (U.S. EPA, 2013, section 6.2.3).[27]

Building on the last review, recent studies continue to support the evidence for airway inflammation and injury with new evidence for such effects following exposures to lower concentrations than had been evaluated previously. These studies include recent controlled human exposure and epidemiologic studies and are discussed more below.

An extensive body of evidence from controlled human exposure studies, described in section II.B.2.a.ii of the proposal, indicates that short-term exposures to O_3 can cause pulmonary inflammation and increases in polymorphonuclear leukocyte (PMN) influx and permeability following 80–600 O_3 ppb exposures, eosinophilic inflammation following exposures at or above 160 ppb, and O_3-induced PMN influx following exposures of healthy adults to 60 ppb O_3, the lowest concentration that has been evaluated for inflammation. A meta-analysis of 21 controlled human exposure studies (Mudway and Kelly, 2004) using varied experimental protocols (80–600 ppb O_3 exposures; 1–6.6 hours exposure duration; light to heavy exercise; bronchoscopy at 0–24 hours post-O_3 exposure) reported that PMN influx in healthy subjects is linearly associated with total O_3 dose.

As with FEV_1 responses to O_3, inflammatory responses to O_3 are generally reproducible within individuals, with some individuals experiencing more severe O_3-induced airway inflammation than indicated by group averages. Unlike O_3-induced decrements in lung function, which are attenuated following repeated exposures over several days, some markers of O_3-induced inflammation and tissue damage remain elevated during repeated exposures, indicating ongoing damage to the respiratory system (79 FR 75252). Most controlled human exposure studies have reported that asthmatics experience larger O_3-induced inflammatory responses than non-asthmatics.[28]

In the previous review (U.S. EPA, 2006a), the epidemiologic evidence of O_3-associated changes in airway inflammation and oxidative stress was limited (79 FR 75253). Since then, as a result of the development of less invasive test methods, there has been a large increase in the number of studies assessing ambient O_3-associated changes in airway inflammation and oxidative stress, the types of biological samples collected, and the types of indicators. Most of these recent studies have evaluated biomarkers of inflammation or oxidative stress in exhaled breath, nasal lavage fluid, or induced sputum (U.S. EPA, 2013, section 6.2.3.2). These recent studies form a larger database to establish coherence with findings from controlled human exposure and animal

[25] Reversible loss of lung function in combination with the presence of symptoms meets ATS criteria for adversity (ATS, 2000a).

[26] Panel studies include repeated measurements of health outcomes, such as respiratory symptoms, at the individual level (U.S. EPA, 2013, p. 1x).

[27] CASAC also addressed this issue: ''The CASAC believes that these modest changes in FEV_1 are usually associated with inflammatory changes, such as more neutrophils in the bronchoalveolar lavage fluid. Such changes may be linked to the pathogenesis of chronic lung disease'' (Frey, 2014a p. 2).

[28] When evaluated, these studies have also reported O_3-induced respiratory symptoms in asthmatics. Specifically, Scannell et al. (1996), Basha et al. (1994), and Vagaggini et al. (2001, 2007) reported increased symptoms in addition to inflammation.

studies that have measured the same or related biological markers. Additionally, results from these studies provide further biological plausibility for the associations observed between ambient O_3 concentrations and respiratory symptoms and asthma exacerbations.

Airway Hyperresponsiveness (AHR)

A strong body of controlled human exposure and animal toxicological studies, most of which were available in the last review of the O_3 NAAQS, report O_3-induced AHR after either acute or repeated exposures (U.S. EPA, 2013, section 6.2.2.2). People with asthma often exhibit increased airway responsiveness at baseline relative to healthy control subjects, and asthmatics can experience further increases in responsiveness following exposures to O_3. Studies reporting increased airway responsiveness after O_3 exposure contribute to a plausible link between ambient O_3 exposures and increased respiratory symptoms in asthmatics, and increased hospital admissions and emergency department visits for asthma (section II.B.2.a.iii, 79 FR 75254; U.S. EPA, 2013, section 6.2.2.2).

Respiratory Symptoms and Medication Use

Respiratory symptoms are associated with adverse outcomes such as limitations in activity, and are the primary reason for people with asthma to use quick relief medication and to seek medical care. Studies evaluating the link between O_3 exposures and such symptoms allow a direct characterization of the clinical and public health significance of ambient O_3 exposure. Controlled human exposure and toxicological studies have described modes of action through which short-term O_3 exposures may increase respiratory symptoms by demonstrating O_3-induced AHR (U.S. EPA, 2013, section 6.2.2) and pulmonary inflammation (U.S. EPA, 2013, section 6.2.3).

The link between subjective respiratory symptoms and O_3 exposures has been evaluated in both controlled human exposure and epidemiologic studies, and the link with medication use has been evaluated in epidemiologic studies. In the last review, several controlled human exposure studies reported respiratory symptoms following exposures to O_3 concentrations at or above 80 ppb. In addition, one study reported such symptoms following exposures to 60 ppb O_3, though the increase was not statistically different from filtered air controls. Epidemiologic studies reported associations between ambient O_3 and respiratory symptoms and medication use in a variety of locations and populations, including asthmatic children living in U.S. cities (U.S. EPA, 2013, pp. 6–1 to 6–2). In the current review, additional controlled human exposure studies have evaluated respiratory symptoms following exposures to O_3 concentrations below 80 ppb and recent epidemiologic studies have evaluated associations with respiratory symptoms and medication use (U.S. EPA, 2013, sections 6.2.1, 6.2.4).

As noted in section II.B.2.a.iv in the proposal (79 FR 75255), the findings for O_3-induced respiratory symptoms in controlled human exposure studies, and the evidence integrated across disciplines describing underlying modes of action, provide biological plausibility for epidemiologic associations observed between short-term increases in ambient O_3 concentration and increases in respiratory symptoms (U.S. EPA, 2013, section 6.2.4).

Most epidemiologic studies of O_3 and respiratory symptoms and medication use have been conducted in children and/or adults with asthma, with fewer studies, and less consistent results, in non-asthmatic populations (U.S. EPA, 2013, section 6.2.4). The 2006 AQCD (U.S. EPA, 2006a; U.S. EPA, 2013, section 6.2.4) concluded that the collective body of epidemiologic evidence indicated that short-term increases in ambient O_3 concentrations are associated with increases in respiratory symptoms in children with asthma. A large body of single-city and single-region studies of asthmatic children provides consistent evidence for associations between short-term increases in ambient O_3 concentrations and increased respiratory symptoms and asthma medication use in children with asthma (U.S. EPA, 2013, Figure 6–12, Table 6–20, section 6.2.4.1). Methodological differences, described in section II.B.2.a.iv of the proposal, among studies make comparisons across recent multicity studies of respiratory symptoms difficult.

Available evidence indicates that O_3-associated increases in respiratory symptoms are not confounded by temperature, pollen, or copollutants (primarily PM) (U.S. EPA, 2013, section 6.2.4.5; Table 6–25). However, identifying the independent effects of O_3 in some studies was complicated due to the high correlations observed between O_3 and PM or different lags and averaging times examined for copollutants. Nonetheless, the ISA noted that the robustness of associations in some studies of individuals with asthma, combined with findings from controlled human exposure studies for the direct effects of O_3 exposure, provide substantial evidence supporting the independent effects of short-term ambient O_3 exposure on respiratory symptoms (U.S. EPA, 2013, section 6.2.4.5).

In summary, both controlled human exposure and epidemiologic studies have reported respiratory symptoms attributable to short-term O_3 exposures. In the last review, the majority of the evidence from controlled human exposure studies in young, healthy adults was for symptoms following exposures to O_3 concentrations at or above 80 ppb. Although studies that have become available since the last review have not reported increased respiratory symptoms in young, healthy adults following exposures with moderate exertion to 60 ppb, one recent study did report increased symptoms following exposure to 72 ppb O_3. As was concluded in the last review, the collective body of epidemiologic evidence indicates that short-term increases in ambient O_3 concentration are associated with increases in respiratory symptoms in children with asthma (U.S. EPA, 2013, section 6.2.4). Recent studies of respiratory symptoms and medication use, primarily in asthmatic children, add to this evidence. In a smaller body of studies, increases in ambient O_3 concentration were associated with increases in respiratory symptoms in adults with asthma.

Lung Host Defense

The mammalian respiratory tract has a number of closely integrated defense mechanisms that, when functioning normally, provide protection from the potential health effects of exposures to a wide variety of inhaled particles and microbes. Based on toxicological and human exposure studies, in the last review EPA concluded that available evidence indicates that short-term O_3 exposures have the potential to impair host defenses in humans, primarily by interfering with alveolar macrophage function. Any impairment in alveolar macrophage function may lead to decreased clearance of microorganisms or nonviable particles. Compromised alveolar macrophage functions in asthmatics may increase their susceptibility to other O_3 effects, the effects of particles, and respiratory infections (U.S. EPA, 2006a).

Relatively few studies conducted since the last review have evaluated the effects of O_3 exposures on lung host defense. As presented in section II.B.2.a.v of the proposal (79 FR 75256), when the available evidence is taken as a whole, the ISA concludes that acute O_3 exposures impair the host defense capability of animals, primarily by depressing alveolar macrophage function and perhaps also by decreasing mucociliary clearance of inhaled particles and microorganisms. Coupled with limited evidence from controlled human exposure studies, this suggests that humans exposed to O_3 could be predisposed to bacterial infections in the lower respiratory tract.

Allergic and Asthma Related Responses

Evidence from controlled human exposure and epidemiologic studies available in the last review indicates that O_3 exposure skews immune responses toward an allergic phenotype and could also make airborne allergens more allergenic, as discussed in more detail in the proposal (79 FR 75257). Evidence from controlled human exposure and animal toxicology studies available in the last review indicates that O_3 may also increase AHR to specific allergen triggers (75 FR 2970, January 19, 2010). When combined with NO_2, O_3 has been shown to enhance nitration of common protein allergens, which may increase their allergenicity (Franze et al., 2005).

Hospital Admissions and Emergency Department Visits

The 2006 AQCD concluded that ''the overall evidence supports a causal relationship between acute ambient O_3 exposures and increased respiratory morbidity resulting in increased emergency department visits and [hospital admissions] during the warm season'' [29] (U.S. EPA, 2006a). This conclusion was ''strongly supported by the human clinical, animal toxicologic[al], and epidemiologic evidence for [O_3-induced] lung function decrements, increased respiratory symptoms, airway inflammation, and airway hyperreactivity'' (U.S. EPA, 2006a).

The results of recent studies largely support the conclusions of the 2006 AQCD (U.S. EPA, 2013, section 6.2.7). Since the completion of the 2006 AQCD, relatively fewer studies, conducted in the U.S., Canada, and Europe, have evaluated associations between short-term O_3 concentrations and respiratory hospital admissions and emergency department visits, with a growing number of studies conducted in Asia. This epidemiologic evidence is discussed in detail in the proposal (79 FR 75258) and in the ISA (U.S. EPA, 2013, section 6.2.7).[30]

In considering this body of evidence, the ISA focused primarily on multicity studies because they examine associations with respiratory-related hospital admissions and emergency department visits over large geographic areas using consistent statistical methodologies (U.S. EPA, 2013, section 6.2.7.1). The ISA also focused on single-city studies that encompassed a large number of daily hospital admissions or emergency department visits, included long study-durations, were conducted in locations not represented by the larger studies, or examined population-specific characteristics that may impact the risk of O_3-related health effects but were not evaluated in the larger studies (U.S. EPA, 2013, section 6.2.7.1). When examining the association between short-term O_3 exposure and respiratory health effects that require medical attention, the ISA distinguishes between hospital admissions and emergency department visits because it is likely that a small percentage of respiratory emergency department visits will be admitted to the hospital; therefore, respiratory emergency department visits may represent potentially less serious, but more common outcomes (U.S. EPA, 2013, section 6.2.7.1).

The collective evidence across studies indicates a mostly consistent positive association between O_3 exposure and respiratory-related hospital admissions and emergency department visits. Moreover, the magnitude of these associations may be underestimated to the extent members of study populations modify their behavior in response to air quality forecasts, and to the extent such behavior modification increases exposure misclassification (U.S. EPA, 2013, Section 4.6.6). Studies examining the potential confounding effects of copollutants have reported that O_3 effect estimates remained relatively robust upon the inclusion of PM and gaseous pollutants in two-pollutant models (U.S. EPA, 2013, Figure 6–20, Table 6–29). Additional studies that conducted copollutant analyses, but did not present quantitative results, also support these conclusions (Strickland et al., 2010; Tolbert et al., 2007; Medina-Ramon et al., 2006; U.S. EPA, 2013, section 6.2.7.5).[31]

In the last review, studies had not evaluated the concentration-response relationship between short-term O_3 exposure and respiratory-related hospital admissions and emergency department visits. As described in the proposal in section II.B.2.a.vii (79 FR 75257) and in the ISA (U.S. EPA, 2013, section 6.2.7.2), a preliminary examination of this relationship in studies that have become available since the last review found no evidence of a deviation from linearity when examining the association between short-term O_3 exposure and asthma hospital admissions (Silverman and Ito, 2010; Strickland et al., 2010). In addition, an examination of the concentration-response relationship for O_3 exposure and pediatric asthma emergency department visits found no evidence of a threshold at O_3 concentrations as low as 30 ppb (for daily maximum 8-hour concentrations) (U.S. EPA, 2013, section 6.2.7.3). However, in these studies there is uncertainty in the shape of the concentration-response curve at the lower end of the distribution of O_3 concentrations due to the low density of data in this range. Further studies at low-level O_3 exposures might reduce this uncertainty.

Respiratory Mortality

Evidence from experimental studies indicates multiple potential pathways of respiratory effects from short-term O_3 exposures, which support the continuum of respiratory effects that could potentially result in respiratory-related mortality in adults (U.S. EPA, 2013, section 6.2.8).[32] The evidence in the last review was inconsistent for associations between short-term O_3 concentrations and respiratory mortality (U.S. EPA, 2006a). New epidemiologic evidence for respiratory mortality is discussed in detail in the ISA (U.S. EPA, 2013, section 6.6) and summarized below. The majority of recent multicity studies have reported positive associations between short-term O_3 exposures and respiratory mortality, particularly during the summer months (U.S. EPA, 2013, Figure 6–36).

[29] Epidemiologic associations for O_3 are more robust during the warm season than during cooler months (*e.g.,* smaller measurement error, less potential confounding by copollutants). The rationale for focusing on warm season epidemiologic studies for O_3 can be found at 72 FR 37838–37840.

[30] The consideration of ambient O_3 concentrations in the locations of these epidemiologic studies are discussed in sections II.D.1.b and II.E.4.a below, for the current standard and for alternative standards, respectively.

[31] The ISA concluded that, ''[o]verall, recent studies provide copollutant results that are consistent with those from the studies evaluated in the 2006 O_3 AQCD [(U.S. EPA, 2006[a]), Figure 7–12, page 7–80 of the 2006 O_3 AQCD], which found that O_3 respiratory hospital admissions risk estimates remained robust to the inclusion of PM in copollutant models (U.S. EPA, 2013, pp. 6–152 to 6–153).

[32] Premature mortality is discussed in more detail below in section II.A.1.b.iv.

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Recent multicity studies from the U.S. (Zanobetti and Schwartz, 2008), Europe (Samoli et al., 2009), Italy (Stafoggia et al., 2010), and Asia (Wong et al., 2010), as well as a multi-continent study (Katsouyanni et al., 2009), reported associations between short-term O_3 concentrations and respiratory mortality (U.S. EPA, 2013, Figure 6–37, page 6–259). With respect to respiratory mortality, summer-only analyses were consistently positive and most were statistically significant. All-year analyses had more mixed results, but most were positive.

Of the studies evaluated, only two studies analyzed the potential for copollutant confounding of the O_3-respiratory mortality relationship (Katsouyanni et al., (2009); Stafoggia et al., (2010)). Based on the results of these analyses, the O_3 respiratory mortality risk estimates appear to be moderately to substantially sensitive (*e.g.,* increased or attenuated) to inclusion of PM_{10}. However, in the APHENA study (Katsouyanni et al., 2009), the mostly every-6th-day sampling schedule for PM_{10} in the Canadian and U.S. datasets greatly reduced their sample size and limits the interpretation of these results (U.S. EPA, 2013, sections 6.2.8 and 6.2.9).

The evidence for associations between short-term O_3 concentrations and respiratory mortality has been strengthened since the last review, with the addition of several large multicity studies. The biological plausibility of the associations reported in these studies is supported by the experimental evidence for respiratory effects.

ii. Respiratory Effects—Long-Term Exposure

Since the last review, the body of evidence indicating the occurrence of respiratory effects due to long-term O_3 exposure has been strengthened. This evidence is discussed in detail in the ISA (U.S. EPA, 2013, Chapter 7) and summarized below for new-onset asthma and asthma prevalence, asthma hospital admissions, pulmonary structure and function, and respiratory mortality.

Asthma is a heterogeneous disease with a high degree of temporal variability. The onset, progression, and symptoms can vary within an individual's lifetime, and the course of asthma may vary markedly in young children, older children, adolescents, and adults. In the previous review, longitudinal cohort studies that examined associations between long-term O_3 exposures and the onset of asthma in adults and children indicated a direct effect of long-term O_3 exposures on asthma risk in adults and effect modification by O_3 in children. Since then, additional studies have evaluated associations with new onset asthma, further informing our understanding of the potential gene-environment interactions, mechanisms, and biological pathways associated with incident asthma.

In children, the relationship between long-term O_3 exposure and new-onset asthma has been extensively studied in the Children's Health Study (CHS), a long-term study that was initiated in the early 1990's which has evaluated effects in several cohorts of children. For this review, recent studies from the CHS provide evidence for gene-environment interactions in effects on new-onset asthma by indicating that the lower risks associated with specific genetic variants are found in children who live in lower O_3 communities. Described in detail in the proposal (79 FR 75259) and in the ISA (U.S. EPA, 2013, section 7.2.1), these studies indicate that the risk for new-onset asthma is related in part to genetic susceptibility, as well as behavioral factors and environmental exposure. Cross-sectional studies by Akinbami et al. (2010) and Hwang et al. (2005) provide further evidence relating O_3 exposures with asthma prevalence. Gene-environment interactions are discussed in detail in Section 5.4.2.1 in the ISA (U.S. EPA, 2013).

In the 2006 AQCD (U.S. EPA, 2006a), studies on O_3-related hospital discharges and emergency department visits for asthma and respiratory disease mainly looked at short-term (daily) metrics. Recent studies continue to indicate that there is evidence for increases in both hospital admissions and emergency department visits in children and adults related to all respiratory outcomes, including asthma, with stronger associations in the warm months.

In the 2006 AQCD (U.S. EPA, 2006a), few epidemiologic studies had investigated the effect of chronic O_3 exposure on pulmonary function. As discussed in the proposal, epidemiologic studies of long-term exposures in both children and adults provide mixed results about the effects of long-term O_3 exposure on pulmonary function and the growth rate of lung function.

Long-term studies in animals allow for greater insight into the potential effects of prolonged exposure to O_3 that may not be easily measured in humans, such as structural changes in the respiratory tract. Despite uncertainties, epidemiologic studies observing associations of O_3 exposure with functional changes in humans can attain biological plausibility in conjunction with long-term toxicological studies, particularly O_3-inhalation studies performed in non-human primates whose respiratory systems most closely resemble that of the human. An important series of studies, discussed in section 7.2.3.2 of the ISA (U.S. EPA, 2013), have used nonhuman primates to examine the effect of O_3 alone, or in combination with an inhaled allergen, house dust mite antigen, on morphology and lung function. Animals exhibit the hallmarks of allergic asthma defined for humans (NHLBI, 2007). These studies and others have demonstrated changes in pulmonary function and airway morphology in adult and infant nonhuman primates repeatedly exposed to environmentally relevant concentrations of O_3 (U.S. EPA, 2013, section 7.2.3.2). As discussed in more detail in the proposal, the studies provide evidence of an O_3-induced change in airway resistance and responsiveness and provide biological plausibility of long-term exposure, or repeated short-term exposures, to O_3 contributing to the effects of asthma in children.

Collectively, evidence from animal studies strongly suggests that chronic O_3 exposure is capable of damaging the distal airways and proximal alveoli, resulting in lung tissue remodeling and leading to apparent irreversible changes. Potentially, persistent inflammation and interstitial remodeling play an important role in the progression and development of chronic lung disease. Further discussion of the modes of action that lead to O_3-induced morphological changes and the mechanisms involved in lifestage susceptibility and developmental effects can be found in the ISA (U.S. EPA, 2013, section 5.3.7, section 5.4.2.4). The findings reported in chronic animal studies offer insight into potential biological mechanisms for the suggested association between seasonal O_3 exposure and reduced lung function development in children as observed in epidemiologic studies (U.S. EPA, 2013, section 7.2.3.1). Further research could help fill in the gaps in our understanding of the mechanisms involved in lifestage susceptibility and developmental effects in children of seasonal or long-term exposure to O_3.

A limited number of epidemiologic studies have assessed the relationship between long-term exposure to O_3 and mortality in adults. The 2006 AQCD concluded that an insufficient amount of evidence existed "to suggest a causal relationship between chronic O_3 exposure and increased risk for

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mortality in humans'' (U.S. EPA, 2006a). Though total and cardio-pulmonary mortality were considered in these studies, respiratory mortality was not specifically considered.

In a recent follow-up analysis of the American Cancer Society cohort (Jerrett et al., 2009), cardiopulmonary deaths were separately subdivided into respiratory and cardiovascular deaths, rather than combined as in the Pope et al. (2002) work. Increased O_3 exposure was associated with the risk of death from respiratory causes, and this effect was robust to the inclusion of $PM_{2.5}$. Additionally, a recent multicity time series study (Zanobetti and Schwartz, 2011), which followed (from 1985 to 2006) four cohorts of Medicare enrollees with chronic conditions that might predispose to O_3-related effects, observed an association between long-term (warm season) exposure to O_3 and elevated risk of mortality in the cohort that had previously experienced an emergency hospital admission due to chronic obstructive pulmonary disease (COPD). A key limitation of this study is the inability to control for $PM_{2.5}$, because data were not available in these cities until 1999.

iii. Cardiovascular Effects—Short-Term Exposure

A relatively small number of studies have examined the potential effect of short-term O_3 exposure on the cardiovascular system. The 2006 AQCD (U.S. EPA, 2006a, p. 8–77) concluded that ''O_3 directly and/or indirectly contributes to cardiovascular-related morbidity,'' but added that the body of evidence was limited. This conclusion was based on a controlled human exposure study that included hypertensive adult males; a few epidemiologic studies of physiologic effects, heart rate variability, arrhythmias, myocardial infarctions, and hospital admissions; and toxicological studies of heart rate, heart rhythm, and blood pressure.

More recently, the body of scientific evidence available that has examined the effect of O_3 on the cardiovascular system has expanded. There is an emerging body of animal toxicological evidence demonstrating that short-term exposure to O_3 can lead to autonomic nervous system alterations (in heart rate and/or heart rate variability) and suggesting that proinflammatory signals may mediate cardiovascular effects. Interactions of O_3 with respiratory tract components result in secondary oxidation product formation and subsequent production of inflammatory mediators, which have the potential to penetrate the epithelial barrier and to initiate toxic effects systemically. In addition, animal toxicological studies of long-term exposure to O_3 provide evidence of enhanced atherosclerosis and ischemia/reperfusion (I/R) injury, corresponding with development of a systemic oxidative, proinflammatory environment. Recent experimental and epidemiologic studies have investigated O_3-related cardiovascular events and are summarized in the ISA (U.S. EPA, 2013, section 6.3).

Controlled human exposure studies discussed in previous reviews have not demonstrated any consistent extrapulmonary effects. In this review, evidence from controlled human exposure studies suggests cardiovascular effects in response to short-term O_3 exposure (U.S. EPA, 2013, section 6.3.1) and provides some coherence with evidence from animal toxicology studies. Controlled human exposure studies also support the animal toxicological studies by demonstrating O_3-induced effects on blood biomarkers of systemic inflammation and oxidative stress, as well as changes in biomarkers that can indicate the potential for increased clotting following O_3 exposures. Increases and decreases in high frequency heart rate variability (HRV) have been reported. These changes in cardiac function observed in animal and human studies provide preliminary evidence for O_3-induced modulation of the autonomic nervous system through the activation of neural reflexes in the lung (U.S. EPA, 2013, section 5.3.2).

Overall, the ISA concludes that the available body of epidemiologic evidence examining the relationship between short-term exposures to O_3 concentrations and cardiovascular morbidity is inconsistent (U.S. EPA, 2013, section 6.3.2.9).

Despite the inconsistent evidence for an association between O_3 concentration and cardiovascular disease (CVD) morbidity, mortality studies indicate a consistent positive association between short-term O_3 exposure and cardiovascular mortality in multicity studies and in a multi-continent study. When examining mortality due to CVD, epidemiologic studies consistently observe positive associations with short-term exposure to O_3. Additionally, there is some evidence for an association between long-term exposure to O_3 and mortality, although the association between long-term ambient O_3 concentrations and cardiovascular mortality can be confounded by other pollutants (U.S. EPA, 2013). The ISA (U.S. EPA, 2013, section 6.3.4) states that taken together, the overall body of evidence across the animal and human studies is sufficient to conclude that there is likely to be a causal relationship between relevant short-term exposures to O_3 and cardiovascular system effects.

iv. Premature Mortality—Short-Term Exposure

The 2006 AQCD concluded that the overall body of evidence was highly suggestive that short-term exposure to O_3 directly or indirectly contributes to nonaccidental and cardiopulmonary-related mortality in adults, but additional research was needed to more fully establish underlying mechanisms by which such effects occur (U.S. EPA, 2006a; U.S. EPA, 2013, p. 2–18). In building on the evidence for mortality from the last review, the ISA states (U.S. EPA, 2013, p. 6–261):

> The evaluation of new multicity studies that examined the association between short-term O_3 exposures and mortality found evidence that supports the conclusions of the 2006 AQCD. These new studies reported consistent positive associations between short-term O_3 exposure and all-cause (nonaccidental) mortality, with associations persisting or increasing in magnitude during the warm season, and provide additional support for associations between O_3 exposure and cardiovascular and respiratory mortality.

The 2006 AQCD reviewed a large number of time-series studies of associations between short-term O_3 exposures and total mortality including single- and multicity studies, and meta-analyses. Available studies reported some evidence for heterogeneity in O_3 mortality risk estimates across cities and across studies. Studies that conducted seasonal analyses reported larger O_3 mortality risk estimates during the warm or summer season. Overall, the 2006 AQCD identified robust associations between various measures of daily ambient O_3 concentrations and all-cause mortality, which could not be readily explained by confounding due to time, weather, or copollutants. With regard to cause-specific mortality, consistent positive associations were reported between short-term O_3 exposure and cardiovascular mortality, with less consistent evidence for associations with respiratory mortality. The majority of the evidence for associations between O_3 and cause-specific mortality were from single-city studies, which had small daily mortality counts and subsequently limited statistical power to detect associations. The 2006 AQCD concluded that ''the overall body of evidence is highly suggestive that O_3 directly or indirectly contributes to nonaccidental and cardiopulmonary-related mortality'' (U.S. EPA, 2013, section 6.6.1).

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Recent studies have strengthened the body of evidence that supports the association between short-term O_3 concentrations and mortality in adults. This evidence includes a number of studies reporting associations with nonaccidental as well as cause-specific mortality. Multi-continent and multicity studies have consistently reported positive and statistically significant associations between short-term O_3 concentrations and all-cause mortality, with evidence for larger mortality risk estimates during the warm or summer months (79 FR 75262; U.S. EPA, 2013 Figure 6–27; Table 6–42). Similarly, evaluations of cause-specific mortality have reported consistently positive associations with O_3, particularly in analyses restricted to the warm season (79 FR 75262; U.S. EPA, 2013 Fig. 6–37; Table 6–53).

In the previous review, multiple uncertainties remained regarding the relationship between short-term O_3 concentrations and mortality, including the extent of residual confounding by copollutants; characterization of the factors that modify the O_3-mortality association; the appropriate lag structure for identifying O_3-mortality effects; and the shape of the O_3-mortality concentration-response function and whether a threshold exists. Many of the studies, published since the last review, have attempted to address one or more of these uncertainties and are described in more detail in the proposal (79 FR 75262 and in the ISA (U.S. EPA, 2013, section 6.6.2).

In particular, recent studies have evaluated different statistical approaches to examine the shape of the O_3-mortality concentration-response relationship and to evaluate whether a threshold exists for O_3-related mortality. These studies are detailed in the proposal (79 FR 75262) and in the ISA (U.S. EPA, 2013, p. 2–32). The ISA reaches the following overall conclusions that the epidemiologic studies identified in the ISA indicated a generally linear C–R function with no indication of a threshold but that there is a lack of data at lower O_3 concentrations and therefore, less certainty in the shape of the C–R curve at the lower end of the distribution (U.S. EPA, 2013, p. 2–32).

c. Adversity of Effects

In making judgments as to when various O_3-related effects become regarded as adverse to the health of individuals, in previous NAAQS reviews, the EPA has relied upon the guidelines published by the ATS and the advice of CASAC. In 2000, the ATS published an official statement on "What Constitutes an Adverse Health Effect of Air Pollution?" (ATS, 2000a), which updated and built upon its earlier guidance (ATS, 1985). The earlier guidance defined adverse respiratory health effects as "medically significant physiologic changes generally evidenced by one or more of the following: (1) Interference with the normal activity of the affected person or persons, (2) episodic respiratory illness, (3) incapacitating illness, (4) permanent respiratory injury, and/or (5) progressive respiratory dysfunction," while recognizing that perceptions of "medical significance" and "normal activity" may differ among physicians, lung physiologists and experimental subjects (ATS, 1985). The more recent guidance concludes that transient, reversible loss of lung function in combination with respiratory symptoms should be considered adverse.[33] However, the committee also recommended "that a small, transient loss of lung function, by itself, should not automatically be designated as adverse" (ATS, 2000a, p. 670).

There is also a more specific consideration of population risk in the 2000 guidance. Specifically, the committee considered that a shift in the risk factor distribution, and hence the risk profile of the exposed population, should be considered adverse, even in the absence of the immediate occurrence of frank illness (ATS, 2000a, p. 668). For example, a population of asthmatics could have a distribution of lung function such that no individual has a level associated with clinically important impairment. Exposure to air pollution could shift the distribution to lower levels of lung function that still do not bring any individual to a level that is associated with clinically relevant effects. However, this would be considered to be adverse because individuals within the population would already have diminished reserve function, and therefore would be at increased risk to further environmental insult (ATS, 2000a, p. 668).

The ATS also concluded in its guidance that elevations of biomarkers such as cell numbers and types, cytokines, and reactive oxygen species may signal risk for ongoing injury and more serious effects or may simply represent transient responses, illustrating the lack of clear boundaries that separate adverse from nonadverse events. More subtle health outcomes also may be connected mechanistically to health effects that are clearly adverse, so that small changes in physiological measures may not appear clearly adverse when considered alone, but may be part of a coherent and biologically plausible chain of related health outcomes that include responses that are clearly adverse, such as mortality (U.S. EPA, 2014c, section 3.1.2.1).

Application of the ATS guidelines to the least serious category of effects[34] related to ambient O_3 exposures, which are also the most numerous and, therefore, are also important from a public health perspective, involves judgments about which medical experts on CASAC panels and public commenters have in the past expressed diverse views. To help frame such judgments, in past reviews, the EPA has defined gradations of individual functional responses (*e.g.,* decrements in FEV_1 and airway responsiveness) and symptomatic responses (*e.g.,* cough, chest pain, wheeze), together with judgments as to the potential impact on individuals experiencing varying degrees of severity of these responses. These gradations were used by the EPA in the 1997 O_3 NAAQS review and slightly revised in the 2008 review (U.S. EPA, 1996b, p. 59; U.S. EPA, 2007, p. 3–72; 72 FR 37849, July 11, 2007). These gradations and impacts are summarized in Tables 3–2 and 3–3 in the 2007 O_3 Staff Paper (U.S. EPA, 2007, pp. 3–74 to 3–75).

For the purpose of estimating potentially adverse lung function decrements in active healthy people, the CASAC panel in the 2008 O_3 NAAQS review indicated that a focus on the mid to upper end of the range of moderate levels of functional responses is most appropriate (*e.g.,* FEV_1 decrements ≥15% but <20%) (Henderson, 2006; U.S. EPA, 2007, p. 3–76). In this review, CASAC reiterated that the "[e]stimation of FEV_1 decrements of ≥15% is appropriate as a scientifically relevant surrogate for adverse health outcomes in active healthy adults" (Frey, 2014c, p. 3).

For the purpose of estimating potentially adverse lung function decrements in people with lung disease, the CASAC panel in the 2008 O_3 NAAQS review indicated that a focus on the lower end of the range of moderate levels of functional responses is most appropriate (*e.g.,* FEV_1 decrements ≥10%) (Henderson, 2006; U.S. EPA, 2007, p. 3–76). In their letter

[33] "In drawing the distinction between adverse and nonadverse reversible effects, this committee recommended that reversible loss of lung function in combination with the presence of symptoms should be considered as adverse" (ATS, 2000a).

[34] These include, for example, the transient and reversible effects demonstrated in controlled human exposure studies, such as lung function decrements or respiratory symptoms.

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advising the Administrator on the reconsideration of the 2008 final decision, CASAC stated that ''[a] 10% decrement in FEV_1 can lead to respiratory symptoms, especially in individuals with pre-existing pulmonary or cardiac disease. For example, people with chronic obstructive pulmonary disease have decreased ventilatory reserve (*i.e.,* decreased baseline FEV_1) such that a ≥ 10% decrement could lead to moderate to severe respiratory symptoms'' (Samet, 2011). In this review, CASAC provided similar advice, stating that ''[a]n FEV_1 decrement of ≥ 10% is a scientifically relevant surrogate for adverse health outcomes for people with asthma and lung disease'', and that such decrements ''could be adverse for people with lung disease'' (Frey, 2014c, pp. 3, 7).

In judging the extent to which these impacts represent effects that should be regarded as adverse to the health status of individuals, in previous NAAQS reviews, the EPA has also considered whether effects were experienced repeatedly during the course of a year or only on a single occasion (U.S. EPA, 2007). While some experts would judge single occurrences of moderate responses to be a ''nuisance,'' especially for healthy individuals, a more general consensus view of the adversity of such moderate responses emerges as the frequency of occurrence increases. In particular, not every estimated occurrence of an O_3-induced FEV_1 decrement will be adverse.[35] However, repeated occurrences of moderate responses, even in otherwise healthy individuals, may be considered to be adverse since they could set the stage for more serious illness (61 FR 65723). The CASAC panel in the 1997 NAAQS review expressed a consensus view that these ''criteria for the determination of an adverse physiological response were reasonable'' (Wolff, 1995). In the review completed in 2008, as in the current review (II.B, II.C below), estimates of repeated occurrences continued to be an important public health policy factor in judging the adversity of moderate lung function decrements in healthy and asthmatic people (72 FR 37850, July 11, 2007).

d. Ozone-Related Impacts on Public Health

The currently available evidence expands the understanding of populations that were identified to be at greater risk of O_3-related health effects at the time of the last review (*i.e.,* people who are active outdoors, people with lung disease, children and older adults and people with increased responsiveness to O_3) and supports the identification of additional factors that may lead to increased risk (U.S. EPA, 2006a, section 6.3; U.S. EPA, 2013, Chapter 8). Populations and lifestages may be at greater risk for O_3-related health effects due to factors that contribute to their susceptibility and/or vulnerability to O_3. The definitions of susceptibility and vulnerability have been found to vary across studies, but in most instances ''susceptibility'' refers to biological or intrinsic factors (*e.g.,* lifestage, sex, preexisting disease/conditions) while ''vulnerability'' refers to non-biological or extrinsic factors (*e.g.,* socioeconomic status [SES]) (U.S. EPA, 2013, p. 8–1; U.S. EPA, 2010, 2009b). In some cases, the terms ''at-risk'' and ''sensitive'' have been used to encompass these concepts more generally. In the ISA, PA, and proposal, ''at-risk'' is the all-encompassing term used to define groups with specific factors that increase their risk of O_3-related health effects.

There are multiple avenues by which groups may experience increased risk for O_3-induced health effects. A population or lifestage [36] may exhibit greater effects than other populations or lifestages exposed to the same concentration or dose, or they may be at greater risk due to increased exposure to an air pollutant (*e.g.,* time spent outdoors). A group with intrinsically increased risk would have some factor(s) that increases risk through a biological mechanism and, in general, would have a steeper concentration-risk relationship, compared to those not in the group. Factors that are often considered intrinsic include pre-existing asthma, genetic background, and lifestage. A group of people could also have extrinsically increased risk, which would be through an external, non-biological factor, such as socioeconomic status (SES) and diet. Some groups are at risk of increased internal dose at a given exposure concentration, for example, because of breathing patterns. This category would include people who work or exercise outdoors. Finally, there are those who might be placed at increased risk for experiencing greater exposures by being exposed to higher O_3 concentrations. This would include, for example, groups of people with greater exposure to ambient O_3 due to less availability or use of home air conditioners such that they are more likely to be in locations with open windows on high O_3 days. Some groups may be at increased risk of O_3-related health effects through a combination of factors. For example, children tend to spend more time outdoors when O_3 levels are high, and at higher levels of activity than adults, which leads to increased exposure and dose, and they also have biological, or intrinsic, risk factors (*e.g.,* their lungs are still developing) (U.S. EPA, 2013, Chapter 8). An at-risk population or lifestage is more likely to experience adverse health effects related to O_3 exposures and/or, develop more severe effects from exposure than the general population. The populations and lifestages identified by the ISA (U.S. EPA, 2013, section 8.5) identified that have ''adequate'' evidence for increased O_3-related health effects are people with certain genotypes, people with asthma, younger and older age groups, people with reduced intake of certain nutrients, and outdoor workers. These at-risk populations and lifestages are described in more detail in section II.B.4 of the proposal (79 FR 75264–269).

One consideration in the assessment of potential public health impacts is the size of various population groups for which there is adequate evidence of increased risk for health effects associated with O_3-related air pollution exposure (U.S. EPA, 2014c, section 3.1.5.2). The factors for which the ISA judged the evidence to be ''adequate'' with respect to contributing to increased risk of O_3-related effects among various populations and lifestages included: Asthma; childhood and older adulthood; diets lower in vitamins C and E; certain genetic variants; and working outdoors (U.S. EPA, 2013, section 8.5). No statistics are available to estimate the size of an at-risk population based on nutritional status or genetic variability.

With regard to asthma, Table 3–7 in the PA (U.S. EPA, 2014c, section 3.1.5.2) summarizes information on the prevalence of current asthma by age in the U.S. adult population in 2010 (Schiller et al. 2012; children—Bloom et al., 2011). Individuals with current asthma constitute a fairly large proportion of the population, including more than 25 million people. Asthma prevalence tends to be higher in children than adults. Within the U.S., approximately 8.2% of adults have reported currently having asthma (Schiller et al., 2012) and 9.5% of

[35] As noted above, the ATS recommended ''that a small, transient loss of lung function, by itself, should not automatically be designated as adverse'' (ATS, 2000a, p. 670).

[36] Lifestages, which in this case includes childhood and older adulthood, are experienced by most people over the course of a lifetime, unlike other factors associated with at-risk populations.

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children have reported currently having asthma (Bloom et al., 2011).[37]

With regard to lifestages, based on U.S. census data from 2010 (Howden and Meyer, 2011), about 74 million people, or 24% of the U.S. population, are under 18 years of age and more than 40 million people, or about 13% of the U.S. population, are 65 years of age or older. Hence, a large proportion of the U.S. population (*i.e.,* more than a third) is included in age groups that are considered likely to be at increased risk for health effects from ambient O_3 exposure.

With regard to outdoor workers, in 2010, approximately 11.7% of the total number of people (143 million people) employed, or about 16.8 million people, worked outdoors one or more days per week (based on worker surveys).[38] Of these, approximately 7.4% of the workforce, or about 7.8 million people, worked outdoors three or more days per week.

While it is difficult to estimate the total number of people in groups that are at greater risk from exposure to O_3, due to the overlap in members of the different at-risk population groups, the proportion of the total population at greater risk is large. The size of the at-risk population combined with the estimates of risk of different health outcomes associated with exposure to O_3 can give an indication of the magnitude of O_3 impacts on public health.

2. Overview of Human Exposure and Health Risk Assessments

To put judgments about health effects into a broader public health context, the EPA has developed and applied models to estimate human exposures to O_3 and O_3-associated health risks. Exposure and risk estimates that are output from such models are presented and assessed in the HREA (U.S. EPA, 2014a). Section II.C of the proposal discusses the quantitative assessments of O_3 exposures and O_3-related health risks that are presented in the HREA (79 FR 75270). Summaries of these discussions are provided below for the approach used to adjust air quality for quantitative exposure and risk analyses in the HREA (II.A.2.a), the HREA assessment of exposures to ambient O_3 (II.A.2.b), and the HREA assessments of O_3-related health risks (II.A.2.c).

a. Air Quality Adjustment

As discussed in section II.C.1 of the proposal (79 FR 75270), the HREA uses a photochemical model to estimate sensitivities of O_3 to changes in precursor emissions in order to estimate ambient O_3 concentrations that would just meet the current and alternative standards (U.S. EPA, 2014a, Chapter 4).[39] For the 15 urban study areas evaluated in the HREA,[40] this model-based adjustment approach estimates hourly O_3 concentrations at each monitor location when modeled U.S. anthropogenic precursor emissions (*i.e.,* NO_X, VOC) [41] are reduced. The HREA estimates air quality that just meets the current and alternative standards for the 2006–2008 and 2008–2010 periods.[42]

As discussed in Chapter 4 of the HREA (U.S. EPA, 2014a), this approach to adjusting air quality models the physical and chemical atmospheric processes that influence ambient O_3 concentrations. Compared to the quadratic rollback approach used in previous reviews, it provides more realistic estimates of the spatial and temporal responses of O_3 to reductions in precursor emissions. Because ambient NO_X can contribute both to the formation and destruction of O_3 (U.S. EPA, 2014a, Chapter 4), the response of ambient O_3 concentrations to reductions in NO_X emissions is more variable than indicated by the quadratic rollback approach. This improved approach to adjusting O_3 air quality is consistent with recommendations from the National Research Council of the National Academies (NRC, 2008). In addition, CASAC strongly supported the new approach as an improvement and endorsed the way it was utilized in the HREA, stating that ''the quadratic rollback approach has been replaced by a scientifically more valid Higher-order Decoupled Direct Method (HDDM)'' and that ''[t]he replacement of the quadratic rollback procedure by the HDDM procedure is important and supported by the CASAC'' (Frey, 2014a, pp. 1 and 3).

Within urban study areas, the model-based air quality adjustments show reductions in the O_3 levels at the upper ends of ambient concentrations and increases in the O_3 levels at the lower ends of those distributions (U.S. EPA, 2014a, section 4.3.3.2, Figures 4–9 and 4–10).[43] Seasonal means of daily O_3 concentrations generally exhibit only modest changes upon model adjustment, reflecting the seasonal balance between daily decreases in relatively higher concentrations and increases in relatively lower concentrations (U.S. EPA, 2014a, Figures 4–9 and 4–10). The resulting compression in the seasonal distributions of ambient O_3 concentrations is evident in all of the urban study areas evaluated, though the degree of compression varies considerably across areas (U.S. EPA, 2014a, Figures 4–9 and 4–10).

As discussed in the PA (U.S. EPA, 2014c, section 3.2.1), adjusted patterns of O_3 air quality have important implications for exposure and risk estimates in urban case study areas. Estimates influenced largely by the upper ends of the distribution of ambient concentrations (*i.e.,* exposures of concern and lung function risk estimates, as discussed in sections 3.2.2 and 3.2.3.1 of the PA) will decrease with model-adjustment to the current and alternative standards. In contrast, seasonal risk estimates influenced by the full distribution of ambient O_3 concentrations (*i.e.,* epidemiology-based risk estimates, as discussed in section 3.2.3.2 of the PA) either increase or decrease in response to air quality adjustment, depending on the balance between the daily decreases in high O_3

[37] As noted below (II.C.3.a.ii), asthmatics can experience larger O_3-induced respiratory effects than non-asthmatic, healthy adults. The responsiveness of asthmatics to O_3 exposures could depend on factors that have not been well-evaluated such as asthma severity, the effectiveness of asthma control, or the prevalence of medication use.

[38] The O*NET program is the nation's primary source of occupational information. Central to the project is the O*NET database, containing information on hundreds of standardized and occupation-specific descriptors. The database, which is available to the public at no cost, is continually updated by surveying a broad range of workers from each occupation. *http://www.onetcenter.org/overview.html. http://www.onetonline.org/find/descriptor/browse/Work_Context/4.C.2/.*

[39] The HREA uses the Community Multi-scale Air Quality (CMAQ) photochemical model instrumented with the higher order direct decoupled method (HDDM) to estimate O_3 concentrations that would occur with the achievement of the current and alternative O_3 standards (U.S. EPA, 2014a, Chapter 4).

[40] The urban study areas assessed are Atlanta, Baltimore, Boston, Chicago, Cleveland, Dallas, Denver, Detroit, Houston, Los Angeles, New York, Philadelphia, Sacramento, St. Louis, and Washington, DC.

[41] Exposure and risk analyses for most of the urban study areas focus on reducing U.S. anthropogenic NO_X emissions alone. The exceptions are Chicago and Denver. Exposure and risk analyses for Chicago and Denver are based on reductions in emissions of both NO_X and VOC (U.S. EPA, 2014a, section 4.3.3.1; Appendix 4D).

[42] These estimates thus reflect design values—8 hour values using the form of the NAAQS that meet the level of the current or alternative standards. These simulations are illustrative and do not reflect any consideration of specific control programs designed to achieve the reductions in emissions required to meet the specified standards. Further, these simulations do not represent predictions of when, whether, or how areas might meet the specified standards.

[43] It is important to note that sensitivity analyses in the HREA indicate that the increases in low O_3 concentrations are smaller when NO_X and VOC emissions are reduced than when only NO_X emissions are reduced (U.S. EPA, 2014a, Appendix 4–D, section 4.7).

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concentrations and increases in low O_3 concentrations.[44]

To evaluate uncertainties in air quality adjustments, the HREA assessed the extent to which the modeled O_3 response to reductions in NO_X emissions appropriately represent the trends observed in monitored ambient O_3 following actual reductions in NO_X emissions, and the extent to which the O_3 response to reductions in precursor emissions could differ with emissions reduction strategies that are different from those used in HREA to generate risk estimates.

To evaluate the first issue, the HREA conducted a national analysis evaluating trends in monitored ambient O_3 concentrations during a time period when the U.S. experienced large-scale reductions in NO_X emissions (*i.e.,* 2001 to 2010). Analyses of trends in monitored O_3 indicate that over such a time period, the upper end of the distribution of monitored O_3 concentrations (*i.e.,* indicated by the 95th percentile) generally decreased in urban and non-urban locations across the U.S. (U.S. EPA, 2014a, Figure 8–29). During this same time period, median O_3 concentrations decreased in suburban and rural locations, and in some urban locations. However, median concentrations increased in some large urban centers (U.S. EPA, 2014a, Figure 8–28). As discussed in the HREA, these increases in median concentrations likely reflect the increases in relatively low O_3 concentrations that can occur near important sources of NO_X upon reductions in NO_X emissions (U.S. EPA, 2014a, section 8.2.3.1). These patterns of monitored O_3 during a period when the U.S. experienced large reductions in NO_X emissions are qualitatively consistent with the modeled responses of O_3 to reductions in NO_X emissions.

To evaluate the second issue, the HREA assessed the O_3 air quality response to reducing both NO_X and VOC emissions (*i.e.,* in addition to assessing reductions in NO_X emissions alone) for a subset of seven urban study areas. As discussed in the PA (U.S. EPA, 2014c, section 3.2.1), the addition of VOC reductions generally resulted in larger decreases in mid-range O_3 concentrations (25th to 75th percentiles) (U.S. EPA, 2014a, Appendix 4D, section 4.7).[45] In addition, in all seven of the urban study areas evaluated, the increases in low O_3 concentrations were smaller for the NO_X/VOC scenarios than the NO_X alone scenarios (U.S. EPA, 2014a, Appendix 4D, section 4.7). This was most apparent for Denver, Houston, Los Angeles, New York, and Philadelphia. Given the impacts on total risk estimates of increases in low O_3 concentrations (discussed below), these results suggest that in some locations optimized emissions reduction strategies could result in larger reductions in O_3-associated mortality and morbidity than indicated by HREA estimates.

b. Exposure Assessment

As discussed in section II.C.2 of the proposal, the O_3 exposure assessment presented in the HREA (U.S. EPA, 2014a, Chapter 5) provides estimates of the number and percent of people exposed to various concentrations of ambient O_3 while at specified exertion levels. The HREA estimates exposures in the 15 urban study areas for four study groups, all school-age children (ages 5 to 18), asthmatic school-age children, asthmatic adults (ages 19 to 95), and all older adults (ages 65 to 95), reflecting the evidence indicating that these populations are at increased risk for O_3-attributable effects (U.S. EPA, 2013, Chapter 8; II.A.1.d, above). An important purpose of these exposure estimates is to provide perspective on the extent to which air quality adjusted to just meet the current O_3 NAAQS could be associated with exposures to O_3 concentrations reported to result in respiratory effects.[46] These analyses of exposure assessment incorporate behavior patterns, including estimates of physical exertion, which are critical in assessing whether ambient concentrations of O_3 may pose a public health risk.[47] In particular, exposures to ambient or near-ambient O_3 concentrations have only been shown to result in potentially adverse effects if the ventilation rates of people in the exposed populations are raised to a sufficient degree (*e.g.,* through physical exertion) (U.S. EPA, 2013, section 6.2.1.1). Estimates of such ''exposures of concern'' provide perspective on the potential public health impacts of O_3-related effects, including effects that cannot currently be evaluated in a quantitative risk assessment.[48]

The HREA estimates 8-hour exposures at or above benchmark concentrations of 60, 70, and 80 ppb for individuals engaged in moderate or greater exertion (*i.e.,* to approximate conditions in the controlled human exposure studies on which benchmarks are based). Benchmarks reflect exposure concentrations at which O_3-induced respiratory effects are known to occur in some healthy adults engaged in moderate, quasi-continuous exertion, based on evidence from controlled human exposure studies (U.S. EPA, 2013, section 6.2; U.S. EPA, 2014c, section 3.1.2.1). The amount of weight to place on the estimates of exposures at or above specific benchmark concentrations depends in part on the weight of the scientific evidence concerning health effects associated with O_3 exposures at those benchmark concentrations. It also depends on judgments about the importance, from a public health perspective, of the health effects that are known or can reasonably be inferred to occur as a result of exposures at benchmark concentrations (U.S. EPA, 2014c, sections 3.1.3, 3.1.5).

In considering estimates of O_3 exposures of concern at or above benchmarks of 60, 70, and 80 ppb, the PA focuses on modeled exposures for school-age children (ages 5–18), including asthmatic school-age children, which are key at-risk populations identified in the ISA (U.S. EPA, 2014c, section 3.1.5). The percentages of children estimated to experience exposures of concern are considerably larger than the percentages estimated for adult populations (*i.e.,* approximately 3-fold larger across urban

[44] In addition, because epidemiology-based risk estimates use ''area-wide'' average O_3 concentrations, calculated by averaging concentrations across multiple monitors in urban case study areas (section 3.2.3.2 below), risk estimates on a given day depend on the daily balance between increasing and decreasing O_3 concentrations at individual monitors.

[45] This was the case for all of the urban study areas evaluated, with the exception of New York (U.S. EPA, 2014a, Appendix 4–D, section 4.7). In this analysis, emissions of NO_X and VOC were reduced by equal percentages, a scenario not likely to reflect the optimal combination for reducing risks. In most of the urban study areas the inclusion of VOC emissions reductions did not alter the NO_X emissions reductions required to meet the current or alternative standards. The exceptions are Chicago and Denver, for which the HREA risk estimates are based on reductions in both NO_X and VOC (U.S. EPA, 2014a, section 4.3.3.1).

[46] In addition, the range of modeled personal exposures to ambient O_3 provide an essential input to the portion of the health risk assessment based on exposure-response functions (for lung function decrements) from controlled human exposure studies. The health risk assessment based on exposure-response information is discussed below (II.C.3).

[47] See 79 FR 75269 ''The activity pattern of individuals is an important determinant of their exposure. Variation in O_3 concentrations among various microenvironments means that the amount of time spent in each location, as well as the level of activity, will influence an individual's exposure to ambient O_3. Activity patterns vary both among and within individuals, resulting in corresponding variations in exposure across a population and over time'' (internal citations omitted).

[48] In this review, the term ''exposure of concern'' is defined as a personal exposure, while at moderate or greater exertion, to 8-hour average ambient O_3 concentrations at and above specific benchmarks levels. As discussed below, these benchmark levels represent exposure concentrations at which O_3-induced health effects are known to occur, or can reasonably be anticipated to occur, in some individuals.

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study areas)[49] (U.S. EPA, 2014a, section 5.3.2 and Figures 5–5 to 5–8). The larger exposure estimates for children are due primarily to the larger percentage of children estimated to spend an extended period of time being physically active outdoors when O_3 concentrations are elevated (U.S. EPA, 2014a, sections 5.3.2 and 5.4.1).

Although exposure estimates differ between children and adults, the patterns of results across the urban study areas and years are similar among all of the populations evaluated (U.S. EPA, 2014a, Figures 5–5 to 5–8). Therefore, while the PA highlights estimates in children, including asthmatic school-age children, it also notes that the patterns of exposures estimated for children represent the patterns estimated for adult asthmatics and older adults.

Table 1 of the proposal (79 FR 75272 to 75273) summarizes key results from the exposure assessment. This table is reprinted below.

TABLE 1—SUMMARY OF ESTIMATED EXPOSURES OF CONCERN IN ALL SCHOOL-AGE CHILDREN FOR THE CURRENT AND ALTERNATIVE O_3 STANDARDS IN URBAN STUDY AREAS

Benchmark concentration	Standard level (ppb)	Average % children exposed [50]	Average number of children exposed [average number of asthmatic children] [51]	% Children—worst year and worst area
One or more exposures of concern per season				
≥ 80 ppb	75	0–0.3 (0.1)	27,000 [3,000]	1.1
	70	0–0.1 (0)	3,700 [300]	0.2
	65	0 (0)	300 [0]	0
	60	0 (0)	100 [52] [0]	0
≥ 70 ppb	75	0.6–3.3 (1.9)	362,000 [40,000]	8.1
	70	0.1–1.2 (0.5)	94,000 [10,000]	3.2
	65	0–0.2 (0.1)	14,000 [2,000]	0.5
	60	0 (0)	1,400 [200]	0.1
≥ 60 ppb	75	9.5–17 (12.2)	2,316,000 [246,000]	25.8
	70	3.3–10.2 (6.2)	1,176,000 [126,000]	18.9
	65	0–4.2 (2.1)	392,000 [42,000]	9.5
	60	0–1.2 (0.4)	70,000 [8,000]	2.2
Two or more exposures of concern per season				
≥ 80 ppb	75	0 (0)	600 [100]	0.1
	70	0 (0)	0 [0]	0
	65	0 (0)	0 [0]	0
	60	0 (0)	0 [0]	0
≥ 70 ppb	75	0.1–0.6 (0.2)	46,000 [5,000]	2.2
	70	0–0.1 (0)	5,400 [600]	0.4
	65	0 (0)	300 [100]	0
	60	0 (0)	0 [0]	0
≥ 60 ppb	75	3.1–7.6 (4.5)	865,000 [93,000]	14.4
	70	0.5–3.5 (1.7)	320,000 [35,000]	9.2
	65	0–0.8 (0.3)	67,000 [7,500]	2.8
	60	0–0.2 (0)	5,100 [700]	0.3

Uncertainties in exposure estimates are summarized in section II.C.2.b of the proposal (79 FR 75273). For example, due to variability in responsiveness, only a subset of individuals who experience exposures at or above a benchmark concentration can be expected to experience health effects.[53] In addition, not all of these effects will be adverse. Given the lack of sufficient exposure-response information for most of the health effects that informed benchmark concentrations, estimates of the number of people likely to experience exposures at or above benchmark concentrations generally cannot be translated into quantitative estimates of the number of people likely to experience specific health effects.[54] The PA views health-relevant exposures as a continuum with greater confidence and less uncertainty about the existence of adverse health effects at higher O_3 exposure concentrations, and less confidence and greater uncertainty as one considers lower exposure concentrations (*e.g.,* U.S. EPA, 2014c,

[49] HREA exposure estimates for all children and asthmatic children are virtually indistinguishable, in terms of the percent estimated to experience exposures of concern (U.S. EPA, 2014a, Chapter 5). Consistent with this, HREA analyses indicate that activity data for people with asthma is generally similar to non-asthmatic populations (U.S. EPA, 2014a, Appendix 5G, Tables 5G2-to 5G–5).

[50] Estimates for each urban case study area were averaged for the years evaluated in the HREA (2006 to 2010). Ranges reflect the ranges across urban study areas. Estimates smaller than 0.05% were rounded downward to zero (from U.S. EPA, 2014a, Tables 5–11 and 5–12). Numbers in parentheses reflect averages across urban study areas, as well as over the years evaluated in the HREA.

[51] Numbers of children exposed in each urban case study area were averaged over the years 2006 to 2010. These averages were then summed across urban study areas. Numbers were rounded to nearest thousand unless otherwise indicated. Estimates smaller than 50 were rounded downward to zero (from U.S. EPA, 2014a, Appendix 5F Table 5F–5).

[52] As discussed in section 4.3.3 of the HREA, the model-based air quality adjustment approach used to estimate exposures and lung function decrements associated with the current and alternative standards was unable to estimate the distribution of ambient O_3 concentrations in New York City upon just meeting an alternative standard with a level of 60 ppb. Therefore, for the 60 ppb standard level, the numbers of children and asthmatic children, and the ranges of percentages, reflect all of the urban study areas except New York.

[53] As noted below (II.C.3.a.ii), in the case of asthmatics, responsiveness to O_3 could depend on factors that have not been well-evaluated, such as asthma severity, the effectiveness of asthma control, or the prevalence of medication use.

[54] The exception to this is lung function decrements, as discussed below (and in U.S. EPA, 2014c, section 3.2.3.1).

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sections 3.1 and 4.6). This view draws from the overall body of available health evidence, which indicates that as exposure concentrations increase, the incidence, magnitude, and severity of effects increases.

Another important uncertainty is that there is very limited evidence from controlled human exposure studies, which provided the basis for health benchmark concentrations for both exposures of concern and lung function decrements, related to clinical responses in at-risk populations. Compared to the healthy young adults included in the controlled human exposure studies, members of at-risk populations could be more likely to experience adverse effects, could experience larger and/or more serious effects, and/or could experience effects following exposures to lower O_3 concentrations.[55]

There are also uncertainties associated with the exposure modelling. These are described most fully, and their potential impact characterized, in section 5.5.2 of the HREA (U.S. EPA, 2013, pp. 5–72 to 5–79). These include interpretation of activity patterns set forth in diaries which do not typically distinguish the basis for activity patterns and so may reflect averting behavior,[56] and whether the HREA underestimates exposures for groups spending especially large proportion of time being active outdoors during the O_3 season (outdoor workers and especially active children).

c. Quantitative Health Risk Assessments

As discussed in section II.C.3 of the proposal (79 FR 75274), for some health endpoints, there is sufficient scientific evidence and information available to support the development of quantitative estimates of O_3-related health risks. In the current review, for short-term O_3 concentrations, the HREA estimates lung function decrements; respiratory symptoms in asthmatics; hospital admissions and emergency department visits for respiratory causes; and all-cause mortality (U.S. EPA, 2014a). For long-term O_3 concentrations, the HREA estimates respiratory mortality (U.S. EPA, 2014a).[57] Estimates of O_3-induced lung function decrements are based on exposure modeling using the MSS model (see section II.1.b.i.(1) above, and 79 FR 75250), combined with exposure-response relationships from controlled human exposure studies (U.S. EPA, 2014a, Chapter 6). Estimates of O_3-associated respiratory symptoms, hospital admissions and emergency department visits, and mortality are based on concentration-response relationships from epidemiologic studies (U.S. EPA, 2014a, Chapter 7). As with the exposure assessment discussed above, O_3-associated health risks are estimated for recent air quality and for ambient concentrations adjusted to just meet the current and alternative O_3 standards, based on 2006–2010 air quality and adjusted precursor emissions. The following sections summarize the discussions from the proposal on the lung function risk assessment (II.A.2.c.i) and the epidemiology-based morbidity and mortality risk assessments (II.A.2.c.ii).

i. Lung Function Risk Assessment

The HREA estimates risks oflung function decrements in school-aged children (ages 5 to 18), asthmatic school-aged children, and the general adult population for the 15 urban study areas. The results presented in the HREA are based on an updated dose-threshold model that estimates FEV_1 responses for individuals following short-term exposures to O_3 (McDonnell et al., 2012), reflecting methodological improvements since the last review (II.B.2.a.i (1), above; U.S. EPA, 2014a, section 6.2.4). The impact of the dose threshold is that O_3-induced FEV_1 decrements result primarily from exposures on days with average ambient O_3 concentrations above about 40 ppb (U.S. EPA, 2014a, section 6.3.1, Figure 6–9).[58]

Table 2 in the proposal (79 FR 75275), and reprinted below, summarizes key results from the lung function risk assessment. Table 2 presents estimates of the percentages of school-aged children estimated to experience O_3-induced FEV_1 decrements >10, 15, or 20% when air quality was adjusted to just meet the current and alternative 8-hour O_3 standards. Table 2 also presents the numbers of children, including children with asthma, estimated to experience such decrements.

TABLE 2—SUMMARY OF ESTIMATED O_3-INDUCED LUNG FUNCTION DECREMENTS FOR THE CURRENT AND POTENTIAL ALTERNATIVE O_3 STANDARDS IN URBAN CASE STUDY AREAS

Lung function decrement	Alternative standard level	Average % children [59]	Number of children (5 to 18 years) [number of asthmatic children] [60]	% Children worst year and area
One or more decrements per season				
≥10%	75	14–19	3,007,000 [312,000]	22
	70	11–17	2,527,000 [261,000]	20
	65	3–15	1,896,000 [191,000]	18
	60	5–11	[61]1,404,000 [139,000]	13
≥15%	75	3–5	766,000 [80,000]	7
	70	2–4	562,000 [58,000]	5
	65	0–3	356,000 [36,000]	4
	60	1–2	225,000 [22,000]	3
≥20%	75	1–2	285,000 [30,000]	2.8
	70	1–2	189,000 [20,000]	2.1
	65	0–1	106,000 [11,000]	1.4
	60	0–1	57,000 [6,000]	0.9

[55] "The CASAC further notes that clinical studies do not address sensitive subgroups, such as children with asthma, and that there is a scientific basis to anticipate that the adverse effects for such subgroups are likely to be more significant at 60 ppb than for healthy adults" (Frey 2014a, p. 7).

[56] See EPA 2014a pp. 5–53 to 54 describing EPA's sensitivity analysis regarding impacts of potential averting behavior for school-age children on the exposure and lung function decrement estimate, and see also section B.2.a.i below.

[57] Estimates of O_3-associated respiratory mortality are based on the study by Jerrett *et al.* (2009). This study used seasonal averages of 1-hour daily maximum O_3 concentrations to estimate long-term concentrations.

[58] Analysis of this issue in the HREA is based on risk estimates in Los Angeles for 2006 unadjusted air quality. The HREA shows that more than 90% of daily instances of FEV_1 decrements ≥10% occur when 8-hr average ambient concentrations are above 40 ppb for this modeled scenario. The HREA notes that the distribution of responses will be different for different study areas, years, and air quality scenarios (U.S. EPA, 2014c, Chapter 6).

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TABLE 2—SUMMARY OF ESTIMATED O_3-INDUCED LUNG FUNCTION DECREMENTS FOR THE CURRENT AND POTENTIAL ALTERNATIVE O_3 STANDARDS IN URBAN CASE STUDY AREAS—Continued

Lung function decrement	Alternative standard level	Average % children [59]	Number of children (5 to 18 years) [number of asthmatic children] [60]	% Children worst year and area
Two or more decrements per season				
≥10%	75	7.5–12	1,730,000 [179,000]	14
	70	5.5–11	1,414,000 [145,000]	13
	65	1.3–8.8	1,023,000 [102,000]	11
	60	2.1–6.4	741,000 [73,000]	7.3
≥15%	75	1.7–2.9	391,000 [40,000]	3.8
	70	0.9–2.4	276,000 [28,000]	3.1
	65	0.1–1.8	168,000 [17,000]	2.3
	60	0.2–1.0	101,000 [10,000]	1.4
≥20%	75	0.5–1.1	128,000 [13,000]	1.5
	70	0.3–0.8	81,000 [8,000]	1.1
	65	0–0.5	43,000 [4,000]	0.8
	60	0–0.2	21,000 [2,000]	0.4

Uncertainties in estimates of lung function risks are summarized in section II.C.3.a.ii of the proposal (79 FR 75275). In addition to the uncertainties noted for exposure estimates, an uncertainty which impacts lung function risk estimates stems from the lack of exposure-response information in children. In the near absence of controlled human exposure data for children, risk estimates are based on the assumption that children exhibit the same lung function response following O_3 exposures as healthy 18 year olds (*i.e.,* the youngest age for which controlled human exposure data is generally available) (U.S. EPA, 2014a, section 6.5.3). This assumption is justified in part by the findings of McDonnell et al. (1985), who reported that children (8–11 years old) experienced FEV_1 responses similar to those observed in adults (18–35 years old) (U.S. EPA, 2014a, p. 3–10). In addition, as discussed in the ISA (U.S. EPA, 2013, section 6.2.1), summer camp studies of school-aged children reported O_3-induced lung function decrements similar in magnitude to those observed in controlled human exposure studies using adults. In extending the risk model to children, the HREA thus fixes the age term in the model at its highest value, the value for age 18. Notwithstanding the information just summarized supporting this approach, EPA acknowledges the uncertainty involved, and notes that the approach could result in either over- or underestimates of O_3-induced lung function decrements in children, depending on how children compare to the adults used in controlled human exposure studies (U.S. EPA, 2014a, section 6.5.3).

A related source of uncertainty is that the risk assessment estimates of O_3-induced decrements in asthmatics used the exposure-response relationship developed from data collected from healthy individuals. Although the evidence has been mixed (U.S. EPA, 2013, section 6.2.1.1), several studies have reported statistically larger, or a tendency toward larger, O_3-induced lung function decrements in asthmatics than in non-asthmatics (Kreit et al., 1989; Horstman et al., 1995; Jorres et al., 1996; Alexis et al., 2000). On this issue, CASAC noted that ''[a]sthmatic subjects appear to be at least as sensitive, if not more sensitive, than non-asthmatic subjects in manifesting O_3-induced pulmonary function decrements'' (Frey, 2014c, p. 4). To the extent asthmatics experience larger O_3-induced lung function decrements than the healthy adults used to develop exposure-response relationships, the HREA could underestimate the impacts of O_3 exposures on lung function in asthmatics, including asthmatic children. The implications of this uncertainty for risk estimates remain unknown at this time (U.S. EPA, 2014a, section 6.5.4), and could depend on a variety of factors that have not been well-evaluated, including the severity of asthma and the prevalence of medication use. However, the available evidence shows responses to O_3 increase with severity of asthma (Horstman et al., 1995) and corticosteroid usage does not prevent O_3 effects on lung function decrements or respiratory symptoms in people with asthma (Vagaggini et al., 2001, 2007).

ii. Mortality and Morbidity Risk Assessments

As discussed in section II.C.3.b of the proposal (79 FR 75276), the HREA estimates O_3-associated risks in 12 urban study areas [62] using concentration-response relationships drawn from epidemiologic studies. These concentration-response relationships are based on ''area-wide'' average O_3 concentrations.[63] The HREA estimates risks for the years 2007 and 2009 in order to provide estimates of risk for a year with generally higher O_3

[59] Estimates in each urban case study area were averaged for the years evaluated in the HREA (2006 to 2010). Ranges reflect the ranges across urban study areas.

[60] Numbers of children estimated to experience decrements in each study urban case study area were averaged over 2006 to 2010. These averages were then summed across urban study areas. Numbers are rounded to nearest thousand unless otherwise indicated.

[61] As discussed in section 4.3.3 of the HREA, the model-based air quality adjustment approach used to estimate risks associated with the current and alternative standards was unable to estimate the distribution of ambient O_3 concentrations in New York City upon just meeting an alternative standard with a level of 60 ppb. Therefore, for the 60 ppb standard level, the numbers of children and asthmatic children experiencing decrements, and the ranges of percentages of such children across study areas, reflect all of the urban study areas except New York City. Because of this, in some cases (*i.e.,* when New York City provided the smallest risk estimate), the lower end of the ranges in Table 2 are higher for a standard level of 60 ppb than for a level of 65 ppb.

[62] The 12 urban areas evaluated are Atlanta, Baltimore, Boston, Cleveland, Denver, Detroit, Houston, Los Angeles, New York, Philadelphia, Sacramento, and St. Louis.

[63] In the epidemiologic studies that provide the health basis for HREA risk assessments, concentration-response relationships are based on daytime O_3 concentrations, averaged across multiple monitors within study areas. These daily averages are used as surrogates for the spatial and temporal patterns of exposures in study populations. Consistent with this approach, the HREA epidemiologic-based risk estimates also utilize daytime O_3 concentrations, averaged across monitors, as surrogates for population exposures. In this notice, we refer to these averaged concentrations as ''area-wide'' O_3 concentrations. Area-wide concentrations are discussed in more detail in section 3.1.4 of the PA (U.S. EPA, 2014c).

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concentrations (2007) and a year with generally lower O_3 concentrations (2009) (U.S. EPA, 2014a, section 7.1.1).

In considering the epidemiology-based risk estimates, the proposal focuses on mortality risks associated with short-term O_3 concentrations. The proposal considers estimates of total risk (*i.e.,* based on the full distributions of ambient O_3 concentrations) and estimates of risk associated with O_3 concentrations in the upper portions of ambient distributions. Both estimates are discussed to provide information that considers risk estimates based on concentration-response relationships being linear over the entire distribution of ambient O_3 concentrations, and thus have the greater potential for morbidity and mortality to be affected by changes in relatively low O_3 concentrations, as well as risk estimates that are associated with O_3 concentrations in the upper portions of the ambient distribution, thus focusing on risk from higher O_3 concentrations and placing greater weight on the uncertainty associated with the shapes of concentration-response curves for O_3 concentrations in the lower portions of the distribution. These results for O_3-associated mortality risk are summarized in Table 3 in the proposal (79 FR 75277).

Important uncertainties in epidemiology-based risk estimates, based on their consideration in the HREA and PA, are discussed in section II.C.3.b.ii of the proposal (79 FR 75277). Compared to estimates of O_3 exposures of concern and estimates of O_3-induced lung function decrements (discussed above), the HREA conclusions reflect lower confidence in epidemiologic-based risk estimates (U.S. EPA, 2014a, section 9.6). In particular, the HREA highlights the heterogeneity in effect estimates between locations, the potential for exposure measurement errors, and uncertainty in the interpretation of the shape of concentration-response functions at lower O_3 concentrations (U.S. EPA, 2014a, section 9.6). The HREA also concludes that lower confidence should be placed in the results of the assessment of respiratory mortality risks associated with long-term O_3, primarily because that analysis is based on only one study, though that study is well-designed, and because of the uncertainty in that study about the existence and identification of a potential threshold in the concentration-response function (U.S. EPA, 2014a, section 9.6).[64,65] This section further discusses some of the key uncertainties in epidemiologic-based risk estimates, as summarized in the PA (U.S. EPA, 2014c, section 3.2.3.2), with a focus on uncertainties that can have particularly important implications for the Administrator's consideration of epidemiology-based risk estimates.

The PA notes that reducing NO_X emissions generally reduces O_3-associated mortality and morbidity risk estimates in locations and time periods with relatively high ambient O_3 concentrations and increases risk estimates in locations and time periods with relatively low concentrations (II.A, above). When evaluating uncertainties in epidemiologic risk estimates, the PA considered (1) the extent to which the modeled O_3 response to reductions in NO_X emissions appropriately represents the trends observed in monitored ambient O_3 following actual reductions in NO_X emissions, (2) the extent to which the O_3 response to reductions in precursor emissions could differ with emissions reduction strategies that are different from those used in HREA to generate risk estimates, and (3) the extent to which estimated changes in risks in urban study areas are representative of the changes that would be experienced broadly across the U.S. population. The first two of these issues are discussed in section II.A.2.c above. The third issue is discussed below.

The HREA conducted national air quality modeling analyses that estimated the proportion of the U.S. population living in locations where seasonal averages of daily O_3 concentrations are estimated to decrease in response to reductions in NO_X emissions, and the proportion living in locations where such seasonal averages are estimated to increase. Given the close relationship between changes in seasonal averages of daily O_3 concentrations and changes in seasonal mortality and morbidity risk estimates, this analysis informs consideration of the extent to which the risk results in urban study areas represent the U.S. population as a whole. This ''representativeness analysis'' indicates that the majority of the U.S. population lives in locations where reducing NO_X emissions would be expected to result in decreases in warm season averages of daily maximum 8-hour ambient O_3 concentrations. Because the HREA urban study areas tend to underrepresent the populations living in such areas (*e.g.,* suburban, smaller urban, and rural areas), risk estimates for the urban study areas are likely to understate the average reductions in O_3-associated mortality and morbidity risks that would be experienced across the U.S. population as a whole upon reducing NO_X emissions (U.S. EPA, 2014a, section 8.2.3.2).

Section 7.4 of the HREA also highlights some additional uncertainties associated with epidemiologic-based risk estimates (U.S. EPA, 2014a). This section of the HREA identifies and discusses sources of uncertainty and presents a qualitative evaluation of key parameters that can introduce uncertainty into risk estimates (U.S. EPA, 2014a, Table 7–4). For several of these parameters, the HREA also presents quantitative sensitivity analyses (U.S. EPA, 2014a, sections 7.4.2 and 7.5.3). Of the uncertainties discussed in Chapter 7 of the HREA, those related to the application of concentration-response functions from epidemiologic studies can have particularly important implications for consideration of epidemiology-based risk estimates, as discussed below.

An important uncertainty is the shape of concentration-response functions at low ambient O_3 concentrations (U.S. EPA, 2014a, Table 7–4).[66] In recognition of the ISA's conclusion that certainty in the shape of O_3 concentration-response functions decreases at low ambient concentrations, the HREA provides estimates of epidemiology-based mortality risks for entire distributions of ambient O_3 concentrations, as well as estimates of total mortality associated with various ambient O_3 concentrations. The PA considers both types of risk estimates, recognizing greater public health concern for adverse O_3-attributable effects at higher ambient O_3 concentrations (which drive higher exposure concentrations, section 3.2.2 of the PA (U.S. EPA, 2014c)), as compared to lower concentrations.

A related consideration is associated with the public health importance of the increases in relatively low O_3 concentrations following air quality adjustment. There is uncertainty that relates to the assumption that the concentration response function for O_3 is linear, such that total risk estimates are equally influenced by decreasing

[64] The CASAC also concluded that ''[i]n light of the potential nonlinearity of the C–R function for long-term exposure reflecting a threshold of the mortality response, the estimated number of premature deaths avoidable for long-term exposure reductions for several levels need to be viewed with caution'' (Frey, 2014a, p. 3).

[65] There is also uncertainty about the extent to which mortality estimates based on the long-term metric used in the study by Jerrett et al. (2009) (*i.e.,* seasonal average of 1-hour daily maximum concentrations) reflects associations with long-term average O_3 versus repeated occurrences of elevated short-term concentrations.

[66] A related uncertainty is the existence, or not, of a threshold. The HREA addresses this issue for long-term O_3 by evaluating risks in models that include potential thresholds (II.D.2.c).

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high concentrations and increasing low concentrations, when the increases and decreases are of equal magnitude. Even on days with increases in relatively low area-wide average concentrations, resulting in increases in estimated risks, some portions of the urban study areas could experience decreases in high O_3 concentrations. To the extent adverse O_3-attributable effects are more strongly supported for higher ambient concentrations (which, as noted above, are consistently reduced upon air quality adjustment), the impacts on risk estimates of increasing low O_3 concentrations reflect an important source of uncertainty. In addition to the uncertainties discussed above, the proposal also notes uncertainties related to (1) using concentration-response relationships developed for a particular population in a particular location to estimate health risks in different populations and locations; (2) using concentration-response functions from epidemiologic studies reflecting a particular air quality distribution to adjusted air quality necessarily reflecting a different (simulated) air quality distribution; (3) using a national concentration-response function to estimate respiratory mortality associated with long-term O_3; and (4) unquantified reductions in risk that could be associated with reductions in the ambient concentrations of pollutants other than O_3, resulting from control of NO_X (79 FR 75277 to 75279).

B. Need for Revision of the Primary Standard

The initial issue to be addressed in the current review of the primary O_3 standard is whether, in view of the advances in scientific knowledge and additional information, it is appropriate to revise the existing standard. This section presents the Administrator's final decision on whether it is ''appropriate'' to revise the current standard within the meaning of section 109 (d)(1) of the CAA. Section II.B.1 contains a summary discussion of the basis for the proposed conclusions on the adequacy of the primary standard. Section II.B.2 discusses comments received on the adequacy of the primary standard. Section II.B.3 presents the Administrator's final conclusions on the adequacy of the current primary standard.

1. Basis for Proposed Decision

In evaluating whether it is appropriate to retain or revise the current standard, the Administrator's considerations build upon those in the 2008 review, including consideration of the broader body of scientific evidence and exposure and health risk information now available, as summarized in sections II.A to II.C (79 FR 75246–75279) of the proposal and section II.A above.

In developing conclusions on the adequacy of the current primary O_3 standard, the Administrator takes into account both evidence-based and quantitative exposure- and risk-based considerations. Evidence-based considerations include the assessment of evidence from controlled human exposure, animal toxicological, and epidemiologic studies for a variety of health endpoints. The Administrator focuses on health endpoints for which the evidence is strong enough to support a ''causal'' or a ''likely to be causal'' relationship, based on the ISA's integrative synthesis of the entire body of evidence. The Administrator's consideration of quantitative exposure and risk information draws from the results of the exposure and risk assessments presented in the HREA.

The Administrator's consideration of the evidence and exposure/risk information is informed by the considerations and conclusions presented in the PA (U.S. EPA, 2014c). The purpose of the PA is to help ''bridge the gap'' between the scientific and technical information assessed in the ISA and HREA, and the policy decisions that are required of the Administrator (U.S. EPA, 2014c, Chapter 1); see also *American Farm Bureau Federation,* 559 F. 3d at 516, 521 (''[a]lthough not required by the statute, in practice EPA staff also develop a Staff Paper, which discusses the information in the Criteria Document that is most relevant to the policy judgments the EPA makes when it sets the NAAQS''). The PA's evidence-based and exposure-/risk-based considerations and conclusions are briefly summarized below in sections II.B.1.a (evidence-based considerations), II.B.1.b (exposure- and risk-based considerations), and II.B.1.c (PA conclusions on the current standard). Section II.B.1.d summarizes CASAC advice to the Administrator and public commenter views on the current standard. Section II.B.1.e presents a summary of the Administrator's proposed conclusions concerning the adequacy of the public health protection provided by the current standard, and her proposed decision to revise that standard.

a. Evidence-Based Considerations From the PA

In considering the available scientific evidence, the PA evaluates the O_3 concentrations in health effects studies (U.S. EPA, 2014c, section 3.1.4). Specifically, the PA characterizes the extent to which health effects have been reported for the O_3 exposure concentrations evaluated in controlled human exposure studies, and effects occurring over the distributions of ambient O_3 concentrations in locations where epidemiologic studies have been conducted. These considerations, as they relate to the adequacy of the current standard, are presented in detail in section 3.1.4 of the PA (U.S. EPA, 2014c) and are summarized in the proposal (79 FR 75279–75287). The PA's considerations are summarized briefly below for controlled human exposure, epidemiologic panel studies, and epidemiologic population-based studies.

Section II.D.1.a of the proposal discusses the PA's consideration of the evidence from controlled human exposure and panel studies. This evidence is assessed in section 6.2 of the ISA (U.S. EPA, 2013) and is summarized in section 3.1.2 of the PA (U.S. EPA, 2014c). A large number of controlled human exposure studies have reported lung function decrements, respiratory symptoms, air inflammation, airway hyperresponsiveness, and/or impaired lung host defense in young, healthy adults engaged in moderate quasi-continuous exertion, following 6.6-hour O_3 exposures. These studies have consistently reported such effects following exposures to O_3 concentrations of 80 ppb or greater. In addition to lung function decrements, available studies have evaluated respiratory symptoms or airway inflammation following exposures to O_3 concentrations below 75 ppb. Table 3–1 in the PA highlights the group mean results of individual controlled human exposure studies that evaluated exposures to O_3 concentrations below 75 ppb. These studies observe the combination of lung function decrements and respiratory symptoms following exposures to O_3 concentrations as low as 72 ppb, and lung function decrements and airway inflammation following exposures to O_3 concentrations as low as 60 ppb (based on group means).

Based on this evidence, the PA notes that controlled human exposure studies have reported a variety of respiratory effects in young, healthy adults following exposures to a wide range of O_3 concentrations for 6.6 hours, including exposures to concentrations below 75 ppb. In particular, the PA further notes that a recent controlled human exposure study reported the combination of lung function decrements and respiratory symptoms in healthy adults engaged in quasi-

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continuous, moderate exertion following 6.6 hour exposures to 72 ppb O_3, a combination of effects that have been classified as adverse based on ATS guidelines for adversity (ATS, 2000a). In addition, a recent study has also reported lung function decrements and pulmonary inflammation following exposure to 60 ppb O_3. Sixty ppb is the lowest exposure concentration for which inflammation has been evaluated and reported to occur, and corresponds to the lowest exposure concentration demonstrated to result in lung function decrements large enough to be judged an abnormal response by ATS (ATS, 2000b). The PA also notes, and CASAC agreed, that these controlled human exposure studies were conducted in healthy adults, while at-risk groups (*e.g.,* children, people with asthma) could experience larger and/or more serious effects. Therefore, the PA concludes that the evidence from controlled human exposure studies provide support that the respiratory effects experienced following exposures to O_3 concentrations lower than 75 ppb would be adverse in some individuals, particularly if experienced by members of at-risk populations (*e.g.,* people with asthma, children).

The PA also notes consistent results in some panel studies of O_3-associated lung function decrements. In particular, the PA notes that epidemiologic panel studies in children and adults consistently indicate O_3-associated lung function decrements when on-site, ambient monitored concentrations were below 75 ppb (although the evidence becomes less consistent at low O_3 concentrations, and the averaging periods involved ranged from 10 minutes to 12 hours (U.S. EPA, 2014c, section 3.2.4.2)).

Section II.D.1.b of the proposal summarizes the PA's analyses of monitored O_3 concentrations in locations of epidemiologic studies. While the majority of the epidemiologic study areas evaluated would have violated the current standard during study periods, the PA makes the following observations with regard to health effect associations at O_3 concentrations likely to have met the current standard:

(1) A single-city study reported positive and statistically significant associations with asthma emergency department visits in children and adults in Seattle, a location that would have met the current standard over the entire study period (Mar and Koenig, 2009).

(2) Additional single-city studies support associations with respiratory morbidity at relatively low ambient O_3 concentrations, including when virtually all monitored concentrations were below the level of the current standard (Silverman and Ito, 2010; Strickland et al., 2010).

(3) Canadian multicity studies reported positive and statistically significant associations with respiratory morbidity or mortality when the majority of study cities, though not all study cities, would have met the current standard over the study period in each of these studies (Cakmak et al., 2006; Dales et al., 2006; Katsouyanni et al., 2009; Stieb et al., 2009).

(4) A U.S. multicity study reported positive and statistically significant associations with mortality when ambient O_3 concentrations were restricted to those likely to have met the current O_3 standard (Bell et al., 2006).

The PA also takes into account important uncertainties in these analyses of air quality in locations of epidemiologic study areas. These uncertainties are summarized in section II.D.1.b.iii of the proposal. Briefly, they include the following: (1) Uncertainty in conclusions about the extent to which multicity effect estimates reflect associations with air quality meeting the current standard, versus air quality violating that standard; (2) uncertainty regarding the potential for thresholds to exist, given that regional heterogeneity in O_3 health effect associations could obscure the presence of thresholds, should they exist; (3) uncertainty in the extent to which the PA appropriately recreated the air quality analyses in the published study by Bell et al. (2006); and (4) uncertainty in the extent to which reported health effects are caused by exposures to O_3 itself, as opposed to other factors such as co-occurring pollutants or pollutant mixtures, particularly at low ambient O_3 concentrations.[67]

In considering the analyses of monitored O_3 air quality in locations of epidemiologic studies, as well as the important uncertainties in these analyses, the PA concludes that these analyses provide support for the occurrence of morbidity and mortality associated with short-term ambient O_3 concentrations likely to meet the current O_3 standard.[68] In considering the evidence as a whole, the PA concludes that (1) controlled human exposure studies provide strong support for the occurrence of adverse respiratory effects following exposures to O_3 concentrations below the level of the current standard and (2) epidemiologic studies provide support for the occurrence of adverse respiratory effects and mortality under air quality conditions that would meet the current standard.

b. Exposure- and Risk-Based Considerations in the PA

In order to further inform judgments about the potential public health implications of the current O_3 NAAQS, the PA considers the exposure and risk assessments presented in the HREA (U.S. EPA, 2014c, section 3.2). Overviews of these exposure and risk assessments, including brief summaries of key results and uncertainties, are provided in section II.A.2 above. Section II.D.2 of the proposal summarizes key observations from the PA related to the adequacy of the current O_3 NAAQS, based on consideration of the HREA exposure assessment, lung function risk assessment, and mortality/morbidity risk assessments (79 FR 75283).

Section II.D.2.a of the proposal summarizes key observations from the PA regarding estimates of O_3 exposures of concern (79 FR 75283). Given the evidence for respiratory effects from controlled human exposure studies, the PA considers the extent to which the current standard would be estimated to protect at-risk populations against exposures of concern to O_3 concentrations at or above the health benchmark concentrations of 60, 70, and 80 ppb (*i.e.,* based on HREA estimates of one or more and two or more exposures of concern). In doing so, the PA notes the CASAC conclusion that (Frey, 2014c, p. 6):

> The 80 ppb-8hr benchmark level represents an exposure level for which there is substantial clinical evidence demonstrating a range of ozone-related effects including lung inflammation and airway responsiveness in healthy individuals. The 70 ppb-8hr benchmark level reflects the fact that in healthy subjects, decreases in lung function and respiratory symptoms occur at concentrations as low as 72 ppb and that these effects almost certainly occur in some people, including asthmatics and others with low lung function who are less tolerant of such effects, at levels of 70 ppb and below. The 60 ppb-8hr benchmark level represents the lowest exposure level at which ozone-

[67] As noted above (section II.A.1.B.i), the ISA concludes that studies that examined the potential confounding effects of copollutants found that O_3 effect estimates remained relatively robust upon the inclusion of PM and gaseous pollutants in two-pollutant models (U.S. EPA, 2013, section 6.2.7.5).

[68] Unlike for the studies of short-term O_3, the available U.S. and Canadian epidemiologic studies evaluating long-term ambient O_3 concentration metrics have not been conducted in locations likely to have met the current 8-hour O_3 standard during the study period, and have not reported concentration-response functions that indicate confidence in health effect associations at O_3 concentrations meeting the current standard (U.S. EPA, 2014c, section 3.1.4.3).

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related effects have been observed in clinical studies of healthy individuals.

For exposures of concern at or above 60 ppb, the proposal highlights the following key observations for air quality adjusted to just meet the current standard:

(1) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 10 to 18% of children in urban study areas to experience one or more exposures of concern at or above 60 ppb. Summing across urban study areas, these percentages correspond to almost 2.5 million children experiencing approximately 4 million exposures of concern at or above 60 ppb during a single O_3 season. Of these children, almost 250,000 are asthmatics.[69]

(2) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 3 to 8% of children in urban study areas to experience two or more exposures of concern to O_3 concentrations at or above 60 ppb. Summing across the urban study areas, these percentages correspond to almost 900,000 children (including almost 90,000 asthmatic children).

(3) In the worst-case years (*i.e.,* those with the largest exposure estimates), the current standard is estimated to allow approximately 10 to 25% of children to experience one or more exposures of concern at or above 60 ppb, and approximately 4 to 14% to experience two or more exposures of concern at or above 60 ppb.

For exposures of concern at or above 70 ppb, the PA highlights the following key observations for air quality adjusted to just meet the current standard:

(1) On average over the years 2006 to 2010, the current standard is estimated to allow up to approximately 3% of children in urban study areas to experience one or more exposures of concern at or above 70 ppb. Summing across urban study areas, almost 400,000 children (including almost 40,000 asthmatic children) are estimated to experience O_3 exposure concentrations at or above 70 ppb during a single O_3 season.

(2) On average over the years 2006 to 2010, the current standard is estimated to allow less than 1% of children in urban study areas to experience two or more exposures of concern to O_3 concentrations at or above 70 ppb.

(3) In the worst-case location and year, the current standard is estimated to allow approximately 8% of children to experience one or more exposures of concern at or above 70 ppb, and approximately 2% to experience two or more exposures of concern, at or above 70 ppb.

For exposures of concern at or above 80 ppb, the PA highlights the observation that the current standard is estimated to allow about 1% or fewer children in urban study areas to experience exposures of concern at or above 80 ppb, even in years with the highest exposure estimates.

Uncertainties in exposure estimates are summarized in section II.C.2.b of the proposal (79 FR 75273), and discussed more fully in the HREA (U.S. EPA, 2014a, section 5.5.2) and the PA (U.S. EPA, 2014c, section 3.2.2). Key uncertainties include the variability in responsiveness following O_3 exposures, resulting in only a subset of exposed individuals experiencing health effects, adverse or otherwise, and the limited evidence from controlled human exposure studies conducted in at-risk populations. In addition, there are a number of uncertainties in the exposure modelling approach used in the HREA, contributing to overall uncertainty in exposure estimates.

Section II.D.2.b of the proposal summarizes key observations from the PA regarding the estimated risk of O_3-induced lung function decrements (79 FR 75283 to 75284). With respect to the lung function decrements that have been evaluated in controlled human exposure studies, the PA considers the extent to which standards with revised levels would be estimated to protect healthy and at-risk populations against one or more, and two or more, moderate (*i.e.,* FEV_1 decrements ≥10% and ≥15%) and large (*i.e.,* FEV_1 decrements ≥20%) lung function decrements. As discussed in section 3.1.3 of the PA (U.S. EPA, 2014c), although some experts would judge single occurrences of moderate responses to be a nuisance, especially for healthy individuals, a more general consensus view of the adversity of moderate lung function decrements emerges as the frequency of occurrence increases.

With regard to decrements ≥10%, the PA highlights the following key observations for air quality adjusted to just meet the current standard:

(1) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 14 to 19% of children in urban study areas to experience one or more lung function decrements ≥10%. Summing across urban study areas, this corresponds to approximately 3 million children experiencing 15 million O_3-induced lung function decrements ≥10% during a single O_3 season. Of these children, about 300,000 are asthmatics.

(2) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 7 to 12% of children in urban study areas to experience two or more O_3-induced lung function decrements ≥10%. Summing across the urban study areas, this corresponds to almost 2 million children (including almost 200,000 asthmatic children) estimated to experience two or more O_3-induced lung function decrements greater than 10% during a single O_3 season.

(3) In the worst-case years, the current standard is estimated to allow approximately 17 to 23% of children in urban study areas to experience one or more lung function decrements ≥10%, and approximately 10 to 14% to experience two or more O_3-induced lung function decrements ≥10%.

With regard to decrements ≥15%, the PA highlights the following key observations for air quality adjusted to just meet the current standard:

(1) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 3 to 5% of children in urban study areas to experience one or more lung function decrements ≤15%. Summing across urban study areas, this corresponds to approximately 800,000 children (including approximately 80,000 asthmatic children) estimated to experience at least one O_3-induced lung function decrement ≤15% during a single O_3 season.

(2) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 2 to 3% of children in urban study areas to experience two or more O_3-induced lung function decrements ≤15%.

(3) In the worst-case years, the current standard is estimated to allow approximately 4 to 6% of children in urban study areas to experience one or more lung function decrements ≤15%, and approximately 2 to 4% to experience two or more O_3-induced lung function decrements ≤15%.

With regard to decrements ≤20%, the PA highlights the following key observations for air quality adjusted to just meet the current standard:

(1) On average over the years 2006 to 2010, the current standard is estimated to allow approximately 1 to 2% of children in urban study areas to experience one or more lung function decrements ≥20%. Summing across

[69] As discussed in section II.C.2.b of the proposal, due to variability in responsiveness, only a subset of individuals who experience exposures at or above a benchmark concentration can be expected to experience adverse health effects.

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urban study areas, this corresponds to approximately 300,000 children (including approximately 30,000 asthmatic children) estimated to experience at least one O_3-induced lung function decrement ≥20% during a single O_3 season.

(2) On average over the years 2006 to 2010, the current standard is estimated to allow less than 1% of children in urban study areas to experience two or more O_3-induced lung function decrements ≥20%.

(3) In the worst-case years, the current standard is estimated to allow approximately 2 to 3% of children to experience one or more lung function decrements ≥20%, and less than 2% to experience two or more O_3-induced lung function decrements ≥20%.

Uncertainties in lung function risk estimates are summarized in section II.C.3.a of the proposal, and discussed more fully in the HREA (U.S. EPA, 2014a, section 6.5) and the PA (U.S. EPA, 2014c, section 3.2.3.1). In addition to the uncertainties noted above for exposure estimates, the key uncertainties associated with estimates of O_3-induced lung function decrements include the paucity of exposure-response information in children and in people with asthma.

Section II.D.2.c of the proposal summarizes key observations from the PA regarding risk estimates of O_3-associated mortality and morbidity (79 FR 75284 to 75285). With regard to total mortality or morbidity associated with short-term O_3, the PA notes the following for air quality adjusted to just meet the current standard:

(1) When air quality was adjusted to the current standard for the 2007 model year (the year with generally ''higher'' O_3-associated risks), 10 of 12 urban study areas exhibited either decreases or virtually no change in estimates of the number of O_3-associated deaths (U.S. EPA, 2014a, Appendix 7B). Increases were estimated in two of the urban study areas (Houston, Los Angeles)[70] (U.S. EPA, 2014a, Appendix 7B).[71]

(2) In focusing on total risk, the current standard is estimated to allow thousands of O_3-associated deaths per year in the urban study areas. In focusing on the risks associated with the upper portions of distributions of ambient concentrations (area-wide concentrations ≤ 40, 60 ppb), the current standard is estimated to allow hundreds to thousands of O_3-associated deaths per year in the urban study areas.

(3) The current standard is estimated to allow tens to thousands of O_3-associated morbidity events per year (*i.e.,* respiratory-related hospital admissions, emergency department visits, and asthma exacerbations).

With regard to respiratory mortality associated with long-term O_3, the PA notes the following for air quality adjusted to just meet the current standard:

(1) Based on a linear concentration-response function, the current standard is estimated to allow thousands of O_3-associated respiratory deaths per year in the urban study areas.

(2) Based on threshold models, HREA sensitivity analyses indicate that the number of respiratory deaths associated with long-term O_3 concentrations could potentially be considerably lower (*i.e.,* by more than 75% if a threshold exists at 40 ppb, and by about 98% if a threshold exists at 56 ppb) (U.S. EPA, 2014a, Figure 7–9).[72]

Compared to the weight given to HREA estimates of exposures of concern and lung function risks, and the weight given to the evidence, the PA places relatively less weight on epidemiologic-based risk estimates. In doing so, the PA notes that the overall conclusions from the HREA likewise reflect less confidence in estimates of epidemiologic-based risks than in estimates of exposures and lung function risks. The determination to attach less weight to the epidemiologic- based estimates reflects the uncertainties associated with mortality and morbidity risk estimates, including the heterogeneity in effect estimates between locations, the potential for exposure measurement errors, and uncertainty in the interpretation of the shape of concentration-response functions at lower O_3 concentrations (U.S. EPA, 2014a, section 9.6).

Uncertainty in the shape of concentration-response functions at lower O_3 concentrations is particularly important to interpreting risk estimates given the approach used to adjust air quality to just meet the current standard, and potential alternative standards, and the resulting compression in the air quality distributions (*i.e.,* decreasing high concentrations and increasing low concentrations) (II.A.2.a, above). Total risk estimates in the HREA are based on the assumption that the concentration response function for O_3 is linear, such that total risk estimates are equally influenced by decreasing high concentrations and increasing low concentrations, when the increases and decreases are of equal magnitude. However, consistent with the PA's consideration of risk estimates, in the proposal the Administrator notes that the overall body of evidence provides stronger support for the occurrence of

[70] As discussed above (II.C.1), in locations and time periods when NO_X is predominantly contributing to O_3 formation (*e.g.,* downwind of important NO_X sources, where the highest O_3 concentrations often occur), model-based adjustment to the current and alternative standards decreases estimated ambient O_3 concentrations compared to recent monitored concentrations (U.S. EPA, 2014a, section 4.3.3.2). In contrast, in locations and time periods when NO_X is predominantly contributing to O_3 titration (*e.g.,* in urban centers with high concentrations of NO_X emissions, where ambient O_3 concentrations are often suppressed and are thus relatively low), model-based adjustment increases ambient O_3 concentrations compared to recent monitored concentrations (U.S. EPA, 2014a, section 4.3.3.2). Changes in epidemiology-based risk estimates depend on the balance between the daily decreases in high O_3 concentrations and increases in low O_3 concentrations following the model-based air quality adjustment. Commenting on this issue, CASAC noted that ''controls designed to reduce the peak levels of ozone (*e.g.,* the fourth-highest annual MDA8) may not be effective at reducing lower levels of ozone on more typical days and may actually increase ozone levels on days where ozone concentrations are low'' (Frey 2014a, p. 2). CASAC further noted that risk results ''suggest that the ozone-related health risks in the urban cores can increase for some of the cities as ozone NAAQS alternatives become more stringent. This is because reductions in nitrogen oxides emissions can lead to less scavenging of ozone and free radicals, resulting in locally higher levels of ozone'' (Frey 2014c, p. 10).

[71] For the 2009 adjusted year (*i.e.,* the year with generally lower O_3 concentrations), changes in risk were generally smaller than in 2007 (*i.e.,* most changes about 2% or smaller). Increases were estimated for Houston, Los Angeles, and New York City.

[72] Risk estimates for respiratory mortality associated with long-term O_3 exposures are based on the study by Jerrett et al. (2009) (U.S. EPA, 2014a, Chapter 7). As discussed above (II.B.2.b.iv) and in the PA (U.S. EPA, 2014c, section 3.1.4.3), Jerrett et al. (2009) reported that when seasonal averages of 1-hour daily maximum O_3 concentrations ranged from 33 to 104 ppb, there was no statistical deviation from a linear concentration-response relationship between O_3 and respiratory mortality across 96 U.S. cities (U.S. EPA, 2013, section 7.7). However, the authors reported ''limited evidence'' for an effect threshold at an O_3 concentration of 56 ppb (p=0.06). In communications with EPA staff (Sasser, 2014), the study authors indicated that it is not clear whether a threshold model is a better predictor of respiratory mortality than the linear model, and that ''considerable caution should be exercised in accepting any specific threshold.''

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O_3-attributable health effects following exposures to O_3 concentrations corresponding to the upper ends of typical ambient distributions (II.E.4.d of the proposal). In addition, even on days with increases in relatively low area-wide average concentrations, resulting in increases in estimated risks, some portions of the urban study areas could experience decreases in high O_3 concentrations. Therefore, to the extent adverse O_3-attributable effects are more strongly supported for higher ambient concentrations (which, as noted above, are consistently reduced upon air quality adjustment), the PA notes that the impacts on risk estimates of increasing low O_3 concentrations reflect an important source of uncertainty.

c. PA Conclusions on the Current Standard

Section II.D.3 of the proposal summarizes the PA conclusions on the adequacy of the existing primary O_3 standard (79 FR 75285). As an initial matter, the PA concludes that reducing precursor emissions to achieve O_3 concentrations that meet the current standard will provide important improvements in public health protection. This initial conclusion is based on (1) the strong body of scientific evidence indicating a wide range of adverse health outcomes attributable to exposures to O_3 concentrations commonly found in the ambient air and (2) estimates indicating decreased occurrences of O_3 exposures of concern and decreased health risks upon meeting the current standard, compared to recent air quality.

In particular, the PA concludes that strong support for this initial conclusion is provided by controlled human exposure studies of respiratory effects, and by quantitative estimates of exposures of concern and lung function decrements based on information in these studies. Analyses in the HREA estimate that the percentages of children (*i.e.,* all children and children with asthma) in urban study areas experiencing exposures of concern, or experiencing abnormal and potentially adverse lung function decrements, are consistently lower for air quality that just meets the current O_3 standard than for recent air quality. The HREA estimates such reductions consistently across the urban study areas evaluated and throughout various portions of individual urban study areas, including in urban cores and the portions of urban study areas surrounding urban cores. These reductions in exposures of concern and O_3-induced lung function decrements reflect the consistent decreases in the highest O_3 concentrations following reductions in precursor emissions to meet the current standard. Thus, populations in both urban and non-urban areas would be expected to experience important reductions in O_3 exposures and O_3-induced lung function risks upon meeting the current standard.

The PA further concludes that support for this initial conclusion is also provided by estimates of O_3-associated mortality and morbidity based on application of concentration-response relationships from epidemiologic studies to air quality adjusted to just meet the current standard. These estimates are based on the assumption that concentration-response relationships are linear over entire distributions of ambient O_3 concentrations, an assumption which has uncertainties that complicate interpretation of these estimates (II.A.2.c.ii). However, risk estimates for effects associated with short- and long-term O_3 exposures, combined with the HREA's national analysis of O_3 responsiveness to reductions in precursor emissions and the consistent reductions estimated for the highest ambient O_3 concentrations, suggest that O_3-associated mortality and morbidity would be expected to decrease nationwide following reductions in precursor emissions to meet the current O_3 standard.

After reaching the initial conclusion that meeting the current primary O_3 standard will provide important improvements in public health protection, and that it is not appropriate to consider a standard that is less protective than the current standard, the PA considers the adequacy of the public health protection that is provided by the current standard. In considering the available scientific evidence, exposure/risk information, advice from CASAC (II.B.1.d, below), and input from the public, the PA reaches the conclusion that the available evidence and information clearly call into question the adequacy of public health protection provided by the current primary standard. In reaching this conclusion, the PA notes that evidence from controlled human exposure studies provides strong support for the occurrence of adverse respiratory effects following exposures to O_3 concentrations below the level of the current standard. Epidemiologic studies provide support for the occurrence of adverse respiratory effects and mortality under air quality conditions that would likely meet the current standard. In addition, based on the analyses in the HREA, the PA concludes that the exposures and risks projected to remain upon meeting the current standard are indicative of risks that can reasonably be judged to be important from a public health perspective. Thus, the PA concludes that the evidence and information provide strong support for giving consideration to revising the current primary standard in order to provide increased public health protection against an array of adverse health effects that range from decreased lung function and respiratory symptoms to more serious indicators of morbidity (*e.g.,* including emergency department visits and hospital admissions), and mortality. In consideration of all of the above, the PA draws the conclusion that it is appropriate for the Administrator to consider revision of the current primary O_3 standard to provide increased public health protection.

d. CASAC Advice

Section II.D.4 of the proposal summarizes CASAC advice regarding the adequacy of the existing primary O_3 standard. Following the 2008 decision to revise the primary O_3 standard by setting the level at 0.075 ppm (75 ppb), CASAC strongly questioned whether the standard met the requirements of the CAA. In September 2009, the EPA announced its intention to reconsider the 2008 standards, issuing a notice of proposed rulemaking in January 2010 (75 FR 2938). Soon after, the EPA solicited CASAC review of that proposed rule and in January 2011, solicited additional advice. This proposal was based on the scientific and technical record from the 2008 rulemaking, including public comments and CASAC advice and recommendations. As further described above (I.D), in the fall of 2011, the EPA did not revise the standard as part of the reconsideration process but decided to defer decisions on revisions to the O_3 standards to the next periodic review, which was already underway. Accordingly, in this section we describe CASAC's advice related to the 2008 final decision and the subsequent reconsideration, as well as its advice on this current review of the O_3 NAAQS that was initiated in September 2008.

In April 2008, the members of the CASAC Ozone Review Panel sent a letter to EPA stating ''[I]n our most-recent letters to you on this subject—dated October 2006 and March 2007—the CASAC unanimously recommended selection of an 8-hour average Ozone NAAQS within the range of 0.060 to 0.70 parts per million [60 to 70 ppb] for the primary (human health-based) Ozone NAAQS'' (Henderson, 2008). In 2010, in response to the EPA's solicitation of advice on the EPA's

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proposed rulemaking as part of the reconsideration, CASAC again stated that the current standard should be revised to provide additional protection to the public health (Samet, 2010):

CASAC fully supports EPA's proposed range of 0.060–0.070 parts per million (ppm) for the 8-hour primary ozone standard. CASAC considers this range to be justified by the scientific evidence as presented in the Air Quality Criteria for Ozone and Related Photochemical Oxidants (March 2006) and Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper (July 2007). As stated in our letters of October 24, 2006, March 26, 2007 and April 7, 2008 to former Administrator Stephen L. Johnson, CASAC unanimously recommended selection of an 8-hour average ozone NAAQS within the range proposed by EPA (0.060 to 0.070 ppm). In proposing this range, EPA has recognized the large body of data and risk analyses demonstrating that retention of the current standard would leave large numbers of individuals at risk for respiratory effects and/or other significant health impacts including asthma exacerbations, emergency room visits, hospital admissions and mortality.

In response to the EPA's request for additional advice on the reconsideration in 2011, CASAC reaffirmed their conclusion that ''the evidence from controlled human and epidemiological studies strongly supports the selection of a new primary ozone standard within the 60–70 ppb range for an 8-hour averaging time'' (Samet, 2011, p ii). As requested by the EPA, CASAC's advice and recommendations were based on the scientific and technical record from the 2008 rulemaking. In considering the record for the 2008 rulemaking, CASAC stated the following to summarize the basis for their conclusions (Samet, 2011, pp. ii to iii):

(1) The evidence available on dose-response for effects of O_3 shows associations extending to levels within the range of concentrations currently experienced in the United States.

(2) There is scientific certainty that 6.6-hour exposures with exercise of young, healthy, non-smoking adult volunteers to concentrations ≥80 ppb cause clinically relevant decrements of lung function.

(3) Some healthy individuals have been shown to have clinically relevant responses, even at 60 ppb.

(4) Since the majority of clinical studies involve young, healthy adult populations, less is known about health effects in such potentially ozone sensitive populations as the elderly, children and those with cardiopulmonary disease. For these susceptible groups, decrements in lung function may be greater than in healthy volunteers and are likely to have a greater clinical significance.

(5) Children and adults with asthma are at increased risk of acute exacerbations on or shortly after days when elevated O_3 concentrations occur, even when exposures do not exceed the NAAQS concentration of 75 ppb.

(6) Large segments of the population fall into what the EPA terms a ''sensitive population group,'' *i.e.,* those at increased risk because they are more intrinsically susceptible (children, the elderly, and individuals with chronic lung disease) and those who are more vulnerable due to increased exposure because they work outside or live in areas that are more polluted than the mean levels in their communities.

With respect to evidence from epidemiologic studies, CASAC stated ''while epidemiological studies are inherently more uncertain as exposures and risk estimates decrease (due to the greater potential for biases to dominate small effect estimates), specific evidence in the literature does not suggest that our confidence on the specific attribution of the estimated effects of ozone on health outcomes differs over the proposed range of 60–70 ppb'' (Samet, 2011, p. 10).

Following its review of the second draft PA in the current review, which considers an updated scientific and technical record since the 2008 rulemaking, CASAC concluded that ''there is clear scientific support for the need to revise the standard'' (Frey, 2014c, p. ii). In particular, CASAC noted the following (Frey, 2014c, p. 5):

[T]he scientific evidence provides strong support for the occurrence of a range of adverse respiratory effects and mortality under air quality conditions that would meet the current standard. Therefore, CASAC unanimously recommends that the Administrator revise the current primary ozone standard to protect public health.[73]

In supporting these conclusions, CASAC judged that the strongest evidence comes from controlled human exposure studies of respiratory effects. The Committee specifically noted that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5). CASAC further judged that ''if subjects had been exposed to ozone using the 8-hour averaging period used in the standard, adverse effects could have occurred at lower concentration'' and that ''the level at which adverse effects might be observed would likely be lower for more sensitive subgroups, such as those with asthma'' (Frey, 2014c, p. 5). With regard to 60 ppb exposures, CASAC noted that ''a level of 60 ppb corresponds to the lowest exposure concentration demonstrated to result in lung function decrements large enough to be judged an abnormal response by ATS and that could be adverse in individuals with lung disease'' (Frey, 2014c, p. 7). The CASAC further noted that ''a level of 60 ppb also corresponds to the lowest exposure concentration at which pulmonary inflammation has been reported'' (Frey, 2014c, p. 7).

In their advice, CASAC also took note of estimates of O_3 exposures of concern and the risk of O_3-induced lung function decrements. With regard to the benchmark concentrations used in estimating exposures of concern, CASAC stated the following (Frey, 2014c, p. 6):

The 80 ppb-8hr benchmark level represents an exposure level for which there is substantial clinical evidence demonstrating a range of ozone-related effects including lung inflammation and airway responsiveness in healthy individuals. The 70 ppb-8hr benchmark level reflects the fact that in healthy subjects, decreases in lung function and respiratory symptoms occur at concentrations as low as 72 ppb and that these effects almost certainly occur in some people, including asthmatics and others with low lung function who are less tolerant of such effects, at levels of 70 ppb and below. The 60 ppb-8hr benchmark level represents the lowest exposure level at which ozone-related effects have been observed in clinical studies of healthy individuals. Based on its scientific judgment, the CASAC finds that the 60 ppb-8hr exposure benchmark is relevant for consideration with respect to adverse effects on asthmatics.

With regard to lung function risk estimates, CASAC concluded that ''estimation of FEV_1 decrements of ≥15% is appropriate as a scientifically relevant surrogate for adverse health outcomes in active healthy adults, whereas an FEV_1 decrement of ≥10% is a scientifically relevant surrogate for adverse health outcomes for people with asthma and lung disease'' (Frey, 2014c, p. 3). The Committee further concluded that ''[a]sthmatic subjects appear to be at least as sensitive, if not more sensitive, than non-asthmatic subjects in manifesting O_3-induced pulmonary function decrements'' (Frey, 2014c, p. 4).

Although CASAC judged that controlled human exposure studies of respiratory effects provide the strongest

[73] CASAC provided similar advice in their letter to the Administrator on the HREA, stating that ''The CASAC finds that the current primary NAAQS for ozone is not protective of human health and needs to be revised'' (Frey, 2014a, p. 15).

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evidence supporting their conclusion on the current standard, the Committee judged that there is also ''sufficient scientific evidence based on epidemiologic studies for mortality and morbidity associated with short-term exposure to ozone at the level of the current standard'' (Frey, 2014c, p. 5) and noted that ''[r]ecent animal toxicological studies support identification of modes of action and, therefore, the biological plausibility associated with the epidemiological findings'' (Frey, 2014c, p. 5).

e. Administrator's Proposed Decision

Section II.D.5 in the proposal (79 FR 75287–75291) discusses the Administrator's proposed conclusions related to the adequacy of the public health protection provided by the current primary O_3 standard, resulting in her proposed decision to revise that standard. These proposed conclusions and her proposed decision, summarized below, were based on the Administrator's consideration of the available scientific evidence, exposure/risk information, the comments and advice of CASAC, and public input that had been received by the time of proposal.

As an initial matter, the Administrator concluded that reducing precursor emissions to achieve O_3 concentrations that meet the current primary O_3 standard will provide important improvements in public health protection, compared to recent air quality. In reaching this initial conclusion, she noted the discussion in section 3.4 of the PA (U.S. EPA, 2014c). In particular, the Administrator noted that this initial conclusion is supported by (1) the strong body of scientific evidence indicating a wide range of adverse health outcomes attributable to exposures to O_3 concentrations commonly measured in the ambient air and (2) estimates indicating decreased occurrences of O_3 exposures of concern and decreased O_3-associated health risks upon meeting the current standard, compared to recent air quality. Thus, she concluded that it would not be appropriate in this review to consider a standard that is less protective than the current standard.[74]

After reaching the initial conclusion that meeting the current primary O_3 standard will provide important improvements in public health protection, and that it is not appropriate to consider a standard that is less protective than the current standard, the Administrator next considered the adequacy of the public health protection that is provided by the current standard. In doing so, the Administrator first noted that studies evaluated since the completion of the 2006 AQCD support and expand upon the strong body of evidence that, in the last review, indicated a causal relationship between short-term O_3 exposures and respiratory health effects, the strongest determination under the ISA's hierarchical system for classifying weight of evidence for causation. Together, experimental and epidemiologic studies support conclusions regarding a continuum of O_3 respiratory effects ranging from small reversible changes in pulmonary function, and pulmonary inflammation, to more serious effects that can result in respiratory-related emergency department visits, hospital admissions, and premature mortality. The Administrator further noted that recent animal toxicology studies support descriptions of modes of action for these respiratory effects and provide support for biological plausibility for the role of O_3 in reported effects. With regard to mode of action, evidence indicates that antioxidant capacity may modify the risk of respiratory morbidity associated with O_3 exposure, and that the inherent capacity to quench (based on individual antioxidant capacity) can be overwhelmed, especially with exposure to elevated concentrations of O_3. In addition, based on the consistency of findings across studies and evidence for the coherence of results from different scientific disciplines, evidence indicates that certain populations are at increased risk of experiencing O_3-related effects, including the most severe effects. These include populations and lifestages identified in previous reviews (*i.e.,* people with asthma, children, older adults, outdoor workers) and populations identified since the last review (*i.e.,* people with certain genotypes related to antioxidant and/or anti-inflammatory status; people with reduced intake of certain antioxidant nutrients, such as Vitamins C and E).

The Administrator further noted that evidence for adverse respiratory health effects attributable to long-term[75] O_3 exposures is much stronger than in previous reviews, and noted the ISA's conclusion that there is ''likely to be'' a causal relationship between such O_3 exposures and adverse respiratory health effects (the second strongest causality determination). She noted that the evidence available in this review includes new epidemiologic studies using a variety of designs and analysis methods, conducted by different research groups in different locations, evaluating the relationships between long-term O_3 exposures and measures of respiratory morbidity and mortality. New evidence supports associations between long-term O_3 exposures and the development of asthma in children, with several studies reporting interactions between genetic variants and such O_3 exposures. Studies also report associations between long-term O_3 exposures and asthma prevalence, asthma severity and control, respiratory symptoms among asthmatics, and respiratory mortality.

In considering the O_3 exposure concentrations reported to elicit respiratory effects, the Administrator agreed with the conclusions of the PA and with the advice of CASAC (Frey, 2014c) that controlled human exposure studies provide the most certain evidence indicating the occurrence of health effects in humans following exposures to specific O_3 concentrations. In particular, she noted that the effects reported in controlled human exposure studies are due solely to O_3 exposures, and interpretation of study results is not complicated by the presence of co-occurring pollutants or pollutant mixtures.

In considering the evidence from controlled human exposure studies, the Administrator first noted that these studies have reported a variety of respiratory effects in healthy adults following exposures to O_3 concentrations of 60, 72, or 80 ppb, and higher. The largest respiratory effects, and the broadest range of effects, have been studied and reported following exposures of healthy adults to 80 ppb O_3 or higher, with most exposure studies conducted at these higher concentrations. She further noted that recent evidence includes controlled human exposure studies reporting the combination of lung function decrements and respiratory symptoms in healthy adults engaged in quasi-continuous, moderate exertion following 6.6 hour exposures to concentrations as low as 72 ppb, and lung function decrements and

[74] Although the Administrator noted that reductions in O_3 precursor emissions (*e.g.,* NO_X; VOC) to achieve O_3 concentrations that meet the current standard could also increase public health protection by reducing the ambient concentrations of pollutants other than O_3 (*e.g.,* $PM_{2.5}$, NO_2), we did not quantitatively analyze these effects, consistent with CASAC advice (Frey, 2014a, p.10). However, the Administrator is not setting the standard to address risks from pollutants other than O_3.

[75] Based on the exposure surrogates used in recent epidemiologic studies of long-term O_3 exposure, it is not possible to distinguish between the impacts of long-term O_3 exposure and exposure to repeated short-term peaks over an O_3 season.

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pulmonary inflammation following exposures to O_3 concentrations as low as 60 ppb. As discussed below, compared to the evidence available in the last review, the Administrator viewed these studies as having strengthened support for the occurrence of abnormal and adverse respiratory effects attributable to short-term exposures to O_3 concentrations below the level of the current standard. The Administrator stated that such exposures to O_3 concentrations below the level of the current standard are potentially important from a public health perspective, given the following:

(1) The combination of lung function decrements and respiratory symptoms reported to occur in healthy adults following exposures to 72 ppb O_3 or higher, while at moderate exertion, meet ATS criteria for an adverse response. In specifically considering the 72 ppb exposure concentration, CASAC noted that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5).

(2) With regard to 60 ppb O_3, CASAC agreed that ''a level of 60 ppb corresponds to the lowest exposure concentration demonstrated to result in lung function decrements large enough to be judged an abnormal response by ATS and that could be adverse in individuals with lung disease'' (Frey, 2014c, p. 7). CASAC further noted that ''a level of 60 ppb also corresponds to the lowest exposure concentration at which pulmonary inflammation has been reported'' (Frey, 2014c, p. 7).

(3) The controlled human exposure studies reporting these respiratory effects were conducted in healthy adults, while at-risk groups (*e.g.,* children, people with asthma) could experience larger and/or more serious effects. In their advice to the Administrator, CASAC concurred with this reasoning (Frey, 2014a, p. 14; Frey, 2014c, p. 5).

(4) These respiratory effects are coherent with the serious health outcomes that have been reported in epidemiologic studies evaluating exposure to O_3 (*e.g.,* respiratory-related hospital admissions, emergency department visits, and mortality).

As noted above, the Administrator's proposed conclusions regarding the adequacy of the current primary O_3 standard placed a large amount of weight on the results of controlled human exposure studies. In particular, given the combination of lung function decrements and respiratory symptoms following 6.6-hour exposures to O_3 concentrations as low as 72 ppb, and given CASAC advice regarding effects at 72 ppb, along with ATS adversity criteria, she concluded that the evidence in this review supports the occurrence of adverse respiratory effects following exposures to O_3 concentrations lower than the level of the current standard.[76] As discussed below, the Administrator further considered information from the broader body of controlled human exposure studies within the context of quantitative estimates of exposures of concern and O_3-induced FEV_1 decrements.

While putting less weight on information from epidemiologic studies than on information from controlled human exposure studies, the Administrator also considered what the available epidemiologic evidence indicates with regard to the adequacy of the public health protection provided by the current primary O_3 standard. She noted that recent epidemiologic studies provide support, beyond that available in the last review, for associations between short-term O_3 exposures and a wide range of adverse respiratory outcomes (including respiratory-related hospital admissions, emergency department visits, and mortality) and with total mortality. Associations with morbidity and mortality are stronger during the warm or summer months, and remain robust after adjustment for copollutants.

In considering information from epidemiologic studies within the context of her conclusions on the adequacy of the current standard, the Administrator considered the extent to which available studies support the occurrence of O_3 health effect associations with air quality likely to be allowed by the current standard. Most of the epidemiologic studies considered by the Administrator were conducted in locations likely to have violated the current standard over at least part of the study period. However, she noted three U.S. single-city studies that support the occurrence of O_3-associated hospital admissions or emergency department visits at ambient O_3 concentrations below the level of the current standard, or when virtually all monitored concentrations were below the level of the current standard (Mar and Koenig, 2009; Silverman and Ito, 2010; Strickland et al., 2010) (section II.D.1 of the proposal). While the Administrator acknowledged greater uncertainty in interpreting air quality for multicity studies, she noted that O_3 associations with respiratory morbidity or mortality have been reported when the majority of study locations (though not all study locations) would likely have met the current O_3 standard. When taken together, the Administrator reached the initial conclusion at proposal that single-city epidemiologic studies and associated air quality information support the occurrence of O_3-associated hospital admissions and emergency department visits for ambient O_3 concentrations likely to have met the current standard, and that air quality analyses in locations of multicity studies provide some support for this conclusion for a broader range of effects, including mortality.

Beyond her consideration of the scientific evidence, the Administrator also considered the results of the HREA exposure and risk analyses in reaching initial conclusions regarding the adequacy of the current primary O_3 standard. In doing so, as noted above, she focused primarily on exposure and risk estimates based on information from controlled human exposure studies (*i.e.,* exposures of concern and O_3-induced lung function decrements) and placed relatively less weight on epidemiologic-based risk estimates.

With regard to estimates of exposures of concern, the Administrator considered the extent to which the current standard provides protection against exposures to O_3 concentrations at or above 60, 70, and 80 ppb. Consistent with CASAC advice (Frey, 2014c), the Administrator focused on children in these analyses of O_3 exposures, noting that estimates for all children and asthmatic children are virtually indistinguishable, in terms of the percent estimated to experience exposures of concern.[77] Though she focused on children, she also recognized that exposures to O_3 concentrations at or above 60 or 70 ppb could be of concern for adults. As discussed in the HREA and PA (and II.C.2.a of the proposal), the patterns of exposure estimates across urban study areas, across years, and across air quality scenarios are similar in adults with asthma, older adults, all children, and children with asthma, though smaller percentages of adult populations are estimated to experience exposures of concern than children and children with asthma. Thus, the Administrator recognized that the exposure patterns for children across years, urban study areas, and air

[76] This CASAC advice and ATS recommendations are discussed in more detail in section II.C.4 below (see also II.A.1.c, above).

[77] As noted above, HREA analyses indicate that activity data for asthmatics is generally similar to non-asthmatics (U.S. EPA, 2014a, Appendix 5G, Tables 5G2-to 5G–5).

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quality scenarios are indicative of the exposure patterns in a broader group of at-risk populations that also includes asthmatic adults and older adults.

She further noted that while single exposures of concern could be adverse for some people, particularly for the higher benchmark concentrations (70, 80 ppb) where there is stronger evidence for the occurrence of adverse effects, she became increasingly concerned about the potential for adverse responses as the number of occurrences increases (61 FR 75122).[78] In particular, she noted that repeated occurrences of the types of effects shown to occur following exposures of concern can have potentially adverse outcomes. For example, repeated occurrences of airway inflammation could potentially result in the induction of a chronic inflammatory state; altered pulmonary structure and function, leading to diseases such as asthma; altered lung host defense response to inhaled microorganisms; and altered lung response to other agents such as allergens or toxins (U.S. EPA, 2013, section 6.2.3). Thus, the Administrator noted that the types of respiratory effects shown to occur in some individuals following exposures to O_3 concentrations from 60 to 80 ppb, particularly if experienced repeatedly, provide a mode of action by which O_3 may cause other more serious effects (*e.g.,* asthma exacerbations). Therefore, the Administrator placed the most weight on estimates of two or more exposures of concern (*i.e.,* as a surrogate for the occurrence of repeated exposures), though she also considered estimates of one or more, particularly for the 70 and 80 ppb benchmarks.[79]

As illustrated in Table 1 (above), the Administrator noted that if the 15 urban study areas evaluated in the HREA were to just meet the current O_3 standard, fewer than 1% of children in those areas would be estimated to experience two or more exposures of concern at or above 70 ppb, though approximately 3 to 8% of children, including approximately 3 to 8% of asthmatic children, would be estimated to experience two or more exposures of concern to O_3 concentrations at or above 60 ppb [80] (based on estimates averaged over the years of analysis). To provide some perspective on these percentages, the Administrator noted that they correspond to almost 900,000 children in urban study areas, including about 90,000 asthmatic children, estimated to experience two or more exposures of concern at or above 60 ppb. Nationally, if the current standard were to be just met, the number of children experiencing such exposures would be larger. In the worst-case year and location (*i.e.,* year and location with the largest exposure estimates), the Administrator noted that over 2% of children are estimated to experience two or more exposures of concern at or above 70 ppb and over 14% are estimated to experience two or more exposures of concern at or above 60 ppb.

Although, as discussed above and in section II.E.4.d of the proposal, the Administrator was less concerned about single occurrences of exposures of concern, she noted that even single occurrences can cause adverse effects in some people, particularly for the 70 and 80 ppb benchmarks. Therefore, she also considered estimates of one or more exposures of concern. As illustrated in Table 1 (above), if the 15 urban study areas evaluated in the HREA were to just meet the current O_3 standard, fewer than 1% of children in those areas would be estimated to experience one or more exposures of concern at or above 80 ppb (based on estimates averaged over the years of analysis). However, approximately 1 to 3% of children, including 1 to 3% of asthmatic children, would be estimated to experience one or more exposures of concern to O_3 concentrations at or above 70 ppb and approximately 10 to 17% would be estimated to experience one or more exposures of concern to O_3 concentrations at or above 60 ppb. In the worst-case year and location, the Administrator noted that over 1% of children are estimated to experience one or more exposures of concern at or above 80 ppb, over 8% are estimated to experience one or more exposures of concern at or above 70 ppb, and about 26% are estimated to experience one or more exposures of concern at or above 60 ppb.

In addition to estimated exposures of concern, the Administrator also considered HREA estimates of the occurrence of O_3-induced lung function decrements. In doing so, she particularly noted CASAC advice that "estimation of FEV_1 decrements of ≥15% is appropriate as a scientifically relevant surrogate for adverse health outcomes in active healthy adults, whereas an FEV_1 decrement of ≥10% is a scientifically relevant surrogate for adverse health outcomes for people with asthma and lung disease" (Frey, 2014c, p. 3). While these surrogates provide perspective on the potential for the occurrence of adverse respiratory effects following O_3 exposures, the Administrator agreed with the conclusion in past reviews that a more general consensus view of the adversity of moderate responses emerges as the frequency of occurrence increases (citing to 61 FR 65722–3) (Dec, 13, 1996). Therefore, in the proposal the Administrator expressed increasing concern about the potential for adversity as the frequency of occurrences increased and, as a result, she focused primarily on estimates of two or more O_3-induced FEV_1 decrements (*i.e.,* as a surrogate for repeated exposures).

When averaged over the years evaluated in the HREA, the Administrator noted that the current standard is estimated to allow about 1 to 3% of children in the 15 urban study areas (corresponding to almost 400,000 children) to experience two or more O_3-induced lung function decrements ≥15%, and to allow about 8 to 12% of children (corresponding to about 180,000 asthmatic children) to experience two or more O_3-induced lung function decrements ≥10%. Nationally, larger numbers of children would be expected to experience such O_3-induced decrements if the current standard were to be just met. The current standard is also estimated to allow about 3 to 5% of children in the urban study areas to experience one or more decrements ≥15% and about 14 to 19% of children to experience one or more decrements ≥10%. In the worst-case year and location, the current standard is estimated to allow 4% of children in the urban study areas to experience two or more decrements ≥15% (and 7% to experience one or more such decrements) and 14% of children to experience two or more decrements ≥10% (and 22% to experience one or more such decrements).[81]

[78] The Administrator noted that not all people who experience an exposure of concern will experience an adverse effect (even members of at-risk populations). For most of the endpoints evaluated in controlled human exposure studies (with the exception of O_3-induced FEV_1 decrements, as discussed below), the number of those experiencing exposures of concern who will experience adverse effects cannot be reliably quantified.

[79] The Administrator's considerations related to estimated O_3 exposures of concern, including her views on estimates of two or more and one or more such exposures, are discussed in more detail within the context of her consideration of public comments on the level of the revised standard and her final decision on level (II.C.4.b and II.C.4.c, below).

[80] Almost no children in those areas would be estimated to experience two or more exposures of concern at or above 80 ppb.

[81] As discussed below (II.C.4), in her consideration of potential alternative standard levels, the Administrator placed less weight on estimates of the risk of O_3-induced FEV_1 decrements. In doing so, she particularly noted that, unlike exposures of concern, the variability in lung

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In further considering the HREA results, the Administrator considered the epidemiology-based risk estimates. Compared to the weight given to HREA estimates of exposures of concern and lung function risks, she placed relatively less weight on epidemiology-based risk estimates. Consistent with the conclusions in the PA, her determination to attach less weight to the epidemiologic-based risk estimates reflected her consideration of key uncertainties, including the heterogeneity in effect estimates between locations, the potential for exposure measurement errors, and uncertainty in the interpretation of the shape of concentration-response functions for O_3 concentrations in the lower portions of ambient distributions (U.S. EPA, 2014a, section 9.6) (section II.D.2 of the proposal).

The Administrator focused on estimates of total mortality risk associated with short-term O_3 exposures.[82] Given the decreasing certainty in the shape of concentration-response functions for area-wide O_3 concentrations at the lower ends of warm season distributions (U.S. EPA, 2013, section 2.5.4.4), the Administrator focused on estimates of risk associated with O_3 concentrations in the upper portions of ambient distributions. Even when considering only area-wide O_3 concentrations from these upper portions of seasonal distributions, the Administrator noted that the current standard is estimated to allow hundreds to thousands of O_3-associated deaths per year in urban study areas (79 FR 75291 citing to section II.C.3 of the proposal).

In addition to the evidence and exposure/risk information discussed above, the Administrator took note of the CASAC advice in the current review and in the 2010 proposed reconsideration of the 2008 decision establishing the current standard. As discussed in more detail above, the current CASAC ''finds that the current NAAQS for ozone is not protective of human health'' and ''unanimously recommends that the Administrator revise the current primary ozone standard to protect public health'' (Frey, 2014c, p. 5).

In consideration of all of the above, the Administrator proposed that the current primary O_3 standard is not adequate to protect public health, and that it should be revised to provide increased public health protection. This proposed decision was based on the Administrator's initial conclusions that the available evidence and exposure and risk information clearly call into question the adequacy of public health protection provided by the current primary standard and, therefore, that the current standard is not requisite to protect public health with an adequate margin of safety. With regard to the evidence, she specifically noted that (1) controlled human exposure studies provide support for the occurrence of adverse respiratory effects following exposures to O_3 concentrations below the level of the current standard (*i.e.,* as low as 72 ppb), and that (2) single-city epidemiologic studies provide support for the occurrence of adverse respiratory effects under air quality conditions that would likely meet the current standard, with multicity studies providing limited support for this conclusion for a broader range of effects (*i.e.,* including mortality). In addition, based on the analyses in the HREA, the Administrator concluded that the exposures and risks projected to remain upon meeting the current standard can reasonably be judged to be important from a public health perspective. Thus, she reached the proposed conclusion that the evidence and information, together with CASAC advice based on their consideration of that evidence and information, provide strong support for revising the current primary standard in order to increase public health protection against an array of adverse effects that range from decreased lung function and respiratory symptoms to more serious indicators of morbidity (*e.g.,* including emergency department visits and hospital admissions), and mortality.

2. Comments on the Need for Revision

The EPA received a large number of comments, more than 430,000 comments, on the proposed decision to revise the current primary O_3 standard. These comments generally fell into one of two broad groups that expressed sharply divergent views.

Many commenters asserted that the current primary O_3 standard is not sufficient to protect public health, especially the health of sensitive groups, with an adequate margin of safety. These commenters agreed with the EPA's proposed decision to revise the current standard to increase public health protection. Among those calling for revisions to the current primary standard were medical groups (*e.g.,* American Academy of Pediatrics (AAP), American Medical Association, American Lung Association (ALA), American Thoracic Society, American Heart Association, and the American College of Occupational and Environmental Medicine); national, state, and local public health and environmental organizations (*e.g.,* the National Association of County and City Health Officials, American Public Health Association, Physicians for Social Responsibility, Sierra Club, Natural Resources Defense Council, Environmental Defense Fund, Center for Biological Diversity, and Earthjustice); the majority of state and local air pollution control authorities that submitted comments (*e.g.,* agencies from California Air Resources Board and Office of Environmental Health Hazard Assessment, Connecticut, Delaware, Iowa, Illinois, Maryland, Minnesota, New Hampshire, New York, North Dakota, Oregon, Pennsylvania, Tennessee, and Wisconsin); the National Tribal Air Association; State organizations (*e.g.,* National Association of Clean Air Agencies (NACAA), Northeast States for Coordinated Air Use Management, Ozone Transport Commission). While all of these commenters agreed with the EPA that the current O_3 standard needs to be revised, many supported a more protective standard than proposed by EPA, as discussed in more detail below (II.C.4). Many individual commenters also expressed similar views.

A second group of commenters, representing industry associations, businesses and some state agencies, opposed the proposed decision to revise the current primary O_3 standard, expressing the view that the current standard is adequate to protect public health, including the health of sensitive groups, and to do so with an adequate margin of safety. Industry and business groups expressing this view included the American Petroleum Institute (API), the Alliance of Automobile Manufacturers (AAM), the American Forest and Paper Association, the Dow Chemical Company, the National Association of Manufacturers, the

function risk estimates across urban study areas is often greater than the differences in risk estimates between various standard levels (Table 2, above). Given this, and the resulting considerable overlap between the ranges of lung function risk estimates for different standard levels, although the Administrator noted her confidence in the lung function risk estimates themselves, she viewed them as providing a more limited basis than exposures of concern for distinguishing between the degree of public health protection provided by alternative standard levels.

[82] In doing so, she concluded that lower confidence should be placed in the results of the assessment of respiratory mortality risks associated with long-term O_3 exposures, primarily because that analysis is based on only one study (even though that study is well-designed) and because of the uncertainty in that study about the existence and identification of a potential threshold in the concentration-response function (U.S. EPA, 2014a, section 9.6) (section II.D.2 of the proposal). CASAC also called into question the extent to which it is appropriate to place confidence in risk estimates for respiratory mortality (Frey, 2014a, p. 11).

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National Mining Association, the U.S. Chamber of Commerce (in a joint comment with other industry groups), and the Utility Air Regulatory Group (UARG). State environmental agencies opposed to revising the current primary O_3 standard included agencies from Arkansas, Georgia, Louisiana, Kansas, Michigan, Mississippi, Nebraska, North Carolina, Ohio, Texas, Virginia, and West Virginia.

The following sections discuss comments submitted by these and other groups, and the EPA's responses to those comments. Comments dealing with overarching issues that are fundamental to EPA's decision-making methodology are addressed in section II.B.2.a. Comments on the health effects evidence, including evidence from controlled human exposure and epidemiologic studies, are addressed in section II.B.2.b. Comments on human exposure and health risk assessments are addressed in section II.B.2.c. Comments on the appropriate indicator, averaging time, form, or level of a revised primary O_3 standard are addressed below in section II.C. In addition to the comments addressed in this preamble, the EPA has prepared a Response to Comments document that addresses other specific comments related to standard setting, as well as comments on implementation- and/or cost-related factors that the EPA may not consider as part of the basis for decisions on the NAAQS. This document is available for review in the docket for this rulemaking and through the EPA's OAQPS TTN Web site (*http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*).

a. Overarching Comments

Some commenters maintained that the proposed rule (and by extension the final rule) is fundamentally flawed because it does not quantify, or otherwise define, what level of protection is ''requisite'' to protect the public health. These commenters asserted that ''EPA has not explained how far above zero-risk it believes is appropriate or how close to background is acceptable. EPA has failed to explain how the current standard is inadequate on this specific basis'' (*e.g.,* UARG, p. 10). These commenters further maintained that the failure to quantify a requisite level of protection ''drastically reduces the value of public participation'' since ''the public does not understand what is driving EPA's decision'' (*e.g.,* UARG, p. 11).

The EPA disagrees with these comments and notes that industry petitioners made virtually the same argument before the D.C. Circuit in *ATA III,* on remand from the Supreme Court, arguing that unless EPA identifies and quantifies a degree of acceptable risk, it is impossible to determine if a NAAQS is requisite (*i.e.,* neither too stringent or insufficiently stringent to protect the public health). The D.C. Circuit rejected petitioners' argument, holding that ''[a]lthough we recognize that the Clean Air Act and circuit precedent require EPA qualitatively to describe the standard governing its selection of particular NAAQS, we have expressly rejected the notion that the Agency must 'establish a measure of the risk to safety it considers adequate to protect public health every time it establish a [NAAQS]''' *ATA III,* 283 F. 3d at 369 (quoting *NRDC* v. *EPA,* 902 F.2d 962, 973 (D.C. Cir. 1990)). The court went on to explain that the requirement is only for EPA to engage in reasoned decision-making, ''not that it definitively identify pollutant levels below which risks to public health are negligible.'' *ATA III,* 283 F. 3d at 370.

Thus, the Administrator is required to exercise her judgment in the face of scientific uncertainty to establish the NAAQS to provide appropriate protection against risks to public health, both known and unknown. As discussed below, in the current review, the Administrator judges that the existing primary O_3 standard is not requisite to protect public health with an adequate margin of safety, a judgment that is consistent with CASAC's conclusion that ''there is clear scientific support for the need to revise the standard'' (Frey, 2014c, p. ii). Further, in section II.C.4 below, the Administrator has provided a thorough explanation of her rationale for concluding that a standard with a level of 70 ppb is requisite to protect public health with an adequate margin of safety, explaining the various scientific uncertainties which circumscribe the range of potential alternative standards, and how she exercised her ''judgment'' (per section 109 (b)(1) of the CAA) in selecting a standard from within that range of scientifically reasonable choices. This ''reasoned decision making'' is what the Act requires, 283 F. 3d at 370, not the quantification advocated by these commenters.

The EPA further disagrees with the comment that a failure to quantify a requisite level of protection impaired or impeded public notice and comment opportunities. In fact, the EPA clearly gave adequate notice of the bases both for determining that the current standard does not afford requisite protection,[83] and for determining how the standard should be revised. In particular, the EPA explained in detail which evidence it considered critical, and the scientific uncertainties that could cause the Administrator to weight that evidence in various ways (79 FR 75308–75310). There were robust comments submitted by commenters from a range of viewpoints on all of these issues, an indication of the adequacy of notice. The public was also afforded multiple opportunities to comment to the EPA and to CASAC during the development of the ISA, REA, and PA. Thus, the EPA does not agree that lack of quantification of a risk level that is ''requisite'' has deprived commenters of adequate notice and opportunity to comment in this proceeding.

Various commenters maintained that it was inappropriate to revise the current NAAQS based on their view that natural background concentrations in several states are at or above O_3 concentrations associated with meeting a NAAQS set at a level less than 75 ppb (presumably retaining the same indicator, form, and averaging time), making the NAAQS impossible for those states to attain and maintain, a result they claim is legally impermissible. In support for their argument, the commenters cite monitoring and modelling results from various areas in the intermountain west, state that EPA analyses provide underestimates of background O_3 and conclude that high concentrations of background O_3[84] exist

[83] See 79 FR 75287–91 (noting, among other things, that exposure to ambient O_3 concentrations below the level of the current standard has been associated with diminished lung function capacity, respiratory symptoms, and respiratory health effects resulting in emergency room visits or hospital admissions, and that a single-city epidemiologic study showed associations with asthma emergency department visits in an area that would have met the current standard over the entire study period). See also Frey 2014c, p. 5 (CASAC reiterated its conclusion, after multiple public comment opportunities, that as a matter of science the current standard ''is not protective of public health'' and provided the bases for that conclusion).

[84] Background O_3 can be generically defined as the portion of O_3 in ambient air that comes from sources outside the jurisdiction of an area and can include natural sources as well as transported O_3 of anthropogenic origin. EPA has identified two specific definitions of background O_3 relevant to this discussion: natural background (NB) and United States background (USB). NB is defined as the O_3 that would exist in the absence of any manmade precursor emissions. USB is defined as that O_3 that would exist in the absence of any manmade emissions inside the U.S. This includes anthropogenic emissions outside the U.S. as well as naturally occurring ozone. In many cases, the comments reference background O_3 only in the generic sense. Unless explicitly noted otherwise, we have assumed all references to background in the comments are intended to refer to USB.

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in many parts of the United States that will ''prevent attainment'' of a revised standard (NMA, p. 5).

The courts have clearly established that ''[a]ttainability and technological feasibility are not relevant considerations in the promulgation of [NAAQS].'' *API* v. *EPA,* 665 F. 2d 1176, 1185 (D.C. Cir. 1981). Further, the courts have clarified that the EPA may consider proximity to background concentrations as a factor in the decision whether and how to revise the NAAQS only in the context of considering standard levels within the range of reasonable values supported by the air quality criteria and judgments of the Administrator. 79 FR 75242–43 (citing *ATA III,* 283 F. 3d at 379). In this review, the overall body of scientific evidence and exposure/risk information, as discussed in Section II.B of this notice, is clear and convincing: The existing standard is not adequate to protect public health with an adequate margin of safety and that the standard needs to be revised to reflect a lower level to provide that protection. The EPA analyses indicate that there may be infrequent instances in a limited number of rural areas where background O_3 would be appreciable but not the sole contributor to an exceedance of the revised NAAQS, but do not indicate U.S. background (USB) O_3 concentrations will prevent attainment of a revised O_3 standard with a level of 70 ppb. USB is defined as that O_3 that would exist even in the absence of any manmade emissions within the United States.

The EPA's estimates of U.S. background ozone concentrations are based on frequently-utilized, state-of-the-science air quality models and are considered reasonable and reliable, not underestimates. In support of their view, the commenters state that monitored (not modelled) ozone concentrations in remote rural locations include instances of 8-hour average concentrations very occasionally higher than 70 ppb. Monitoring data from places like the Grand Canyon and Yellowstone National Parks, are examples cited in comments. It is inappropriate to assume that monitored O_3 concentrations at remote sites can be used as a proxy for background O_3. Even at the most remote locations, local O_3 concentrations are impacted by anthropogenic emissions from within the U.S. The EPA modeling analyses (U.S. EPA, 2014c, Figure 2–18) estimate that, on a seasonal basis, 10–20% of the O_3 at even the most remote locations in the intermountain western U.S. originates from manmade emissions from the U.S., and thus is not part of USB. This conclusion is supported by commenter-submitted recent data analyses of rural O_3 observations in Nevada and Utah (NMA, Appendices D and H). These analyses conclude that natural sources, international O_3 transport, O_3 transported from upwind states, and O_3 transported from urban areas within a state all contributed to O_3 concentrations at rural sites.[85] Thus, while O_3 in high-altitude, rural portions of the intermountain western U.S. can, at times, be substantially influenced by background sources such as wildfires, international transport or the stratosphere, measured O_3 in rural locations are also influenced by domestic emissions and so cannot, by themselves, be used to estimate USB concentrations. Accordingly, the fact that 2011–2013 design values in locations like Yellowstone National Park (66 ppb) or Grand Canyon National Park (72 ppb) approach or exceed 70 ppb, does not support the conclusion that a standard with a level of 70 ppb is impossible to attain.

To accurately estimate USB concentrations, it is necessary to use air quality models which can estimate how much of the O_3 at any given location originates from sources other than manmade emissions within the U.S. As part of the rulemaking, the EPA has summarized a variety of modeling-based analyses of background O_3 (U.S. EPA, 2013, Chapter 3) and conducted our own multi-model assessment of USB concentrations across the U.S. (U.S. EPA, 2014c, Chapter 2). The EPA analyses, which are consistent with the previously-summarized studies highlighted by commenters, concluded that seasonal mean daily maximum 8-hour average concentrations of USB O_3 range from 25–50 ppb, with the highest estimates located across the intermountain western U.S.

Importantly, the modeling analyses also indicate that the highest O_3 days (*i.e.,* the days most relevant to the form of the NAAQS) generally have similar daily maximum 8-hour average USB concentrations as the seasonal means of this metric, but have larger contributions from U.S. anthropogenic sources. As summarized in the PA, ''the highest modeled O_3 site-days tend to have background O_3 levels similar to mid-range O_3 days . . . [T]he days with highest O_3 levels have similar distributions (*i.e.* means, inter-quartile ranges) of background levels as days with lower values, down to approximately 40 ppb. *As a result, the proportion of total O_3 that has background origins is smaller on high O_3 days (e.g. greater than 60 ppb) than on the more common lower O_3 days that tend to drive seasonal means''* (U.S. EPA, 2014c, p. 2–21, emphasis added). When averaged over the entire U.S., the models estimate that the mean USB fractional contribution to daily maximum 8-hour average O_3 concentrations above 70 ppb is less than 35 percent. U.S. anthropogenic emission sources are thus the dominant contributor to the majority of modeled O_3 exceedances across the U.S. (U.S. EPA, 2014c, Figures 2–14 and 2–15).

As noted in the PA, and as highlighted by the commenters based on existing modeling, there can be infrequent events where daily maximum 8-hour O_3 concentrations approach or exceed 70 ppb largely due to the influence of USB sources like a wildfire or stratospheric intrusion. As discussed below in Section V, the statute and EPA implementing regulations allow for the exclusion of air quality monitoring data from design value calculations when there are exceedances caused by certain event-related U.S. background influences (*e.g.,* wildfires or stratospheric intrusions). As a result, these ''exceptional events'' will not factor into attainability concerns.

In sum, the EPA believes that the commenters have failed to establish the predicate for their argument. Uncontrollable background concentrations of O_3 are not expected to preclude attainment of a revised O_3 standard with a level of 70 ppb. The EPA also disagrees with aspects of the specific statements made by the commenters as support for their view that the EPA analyses have underestimated background O_3.[86] Thus, even assuming the commenters are correct that the EPA may use proximity to background as a justification for not revising a standard that, in the judgment of the Administrator, is inadequate to protect public health, the commenters' arguments for the justification and need to do so for this review are based on a flawed premise.

b. Comments on the Health Effects Evidence

As noted above, comments on the adequacy of the current standard fell into two broad categories reflecting very

[85] The analysis of observations in Utah notes the influence of domestic emissions—either from Salt Lake City (for two of the areas) or from Los Angeles and California (for the third of the areas)—on O_3 concentrations at each of the locations included (NMA comments, Appendix E). Additionally, the analysis of monitoring data for Nevada also describes the influence of the monitoring sites by domestic emissions from other western states (NMA, Appendix H).

[86] Specific aspects of the comments on the EPA analyses are addressed in more detail in the RTC.

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different views of the available scientific evidence. Commenters who expressed support for the EPA's proposed decision to revise the current primary O_3 standard generally concluded that the body of scientific evidence assessed in the ISA is much stronger and more compelling than in the last review. These commenters also generally emphasized CASAC's interpretation of the body of available evidence, which formed an important part of the basis for CASAC's reiterated recommendations to revise the O_3 standard to provide increased public health protection. In some cases, these commenters supported their positions by citing studies published since the completion of the ISA.

The EPA generally agrees with these commenters regarding the need to revise the current primary O_3 standard in order to increase public health protection though, in many cases, not with their conclusions about the degree of protection that is appropriate (II.C.4.b and II.C.4.c, below). The scientific evidence noted by these commenters was generally the same as that assessed in the ISA (U.S. EPA, 2013) and the proposal,[87] and their interpretation of the evidence was often, though not always, consistent with the conclusions of the ISA and CASAC. The EPA agrees that the evidence available in this review provides a strong basis for the conclusion that the current O_3 standard is not adequately protective of public health. In reaching this conclusion, the EPA places a large amount of weight on the scientific advice of CASAC, and on CASAC's endorsement of the assessment of the evidence in the ISA (Frey and Samet, 2012).

In contrast, while commenters who opposed the proposed decision to revise the primary O_3 standard generally focused on many of the same studies assessed in the ISA, these commenters highlighted different aspects of these studies and reached substantially different conclusions about their strength and the extent to which progress has been made in reducing uncertainties in the evidence since the last review. These commenters generally concluded that information about the health effects of concern has not changed significantly since 2008 and that the uncertainties in the underlying health science have not been reduced since the 2008 review. In some cases, these commenters specifically questioned the EPA's approach to assessing the scientific evidence and to reaching conclusions on the strength of that evidence in the ISA. For example, several commenters asserted that the EPA's causal framework, discussed in detail in the ISA, is flawed and that it has not been applied consistently across health endpoints. Commenters also noted departures from other published causality frameworks (Samet and Bodurow, 2008) and from the criteria for judging causality put forward by Sir Austin Bradford Hill (Hill, 1965).

The EPA disagrees with comments questioning the ISA's approach to assessing the evidence, the causal framework established in the ISA, or the consistent application of that framework across health endpoints. While the EPA acknowledges the ISA's approach departs from assessment and causality frameworks that have been developed for other purposes, such departures reflect appropriate adaptations for the NAAQS. As with other ISAs, the O_3 ISA uses a five-level hierarchy that classifies the weight of evidence for causation. In developing this hierarchy, the EPA has drawn on the work of previous evaluations, most prominently the IOM's *Improving the Presumptive Disability Decision-Making Process for Veterans* (Samet and Bodurow, 2008), EPA's Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), and the U.S. Surgeon General's smoking report (CDC, 2004). The ISA's weight of evidence evaluation is based on the integration of findings from various lines of evidence from across the health and environmental effects disciplines. These separate judgments are integrated into a qualitative statement about the overall weight of the evidence and causality. The ISA's causal framework has been developed over multiple NAAQS reviews, based on extensive interactions with CASAC and based on the public input received as part of the CASAC review process. In the current review, the causality framework, and the application of that framework to causality determinations in the O_3 ISA, have been reviewed and endorsed by CASAC (Frey and Samet, 2012).

Given these views on the assessment of the evidence in the ISA, it is relevant to note that many of the issues and concerns raised by commenters on the EPA's interpretation of the evidence, and on the EPA's conclusions regarding the extent to which uncertainties have been reduced since the 2008 review, are essentially restatements of issues raised during the development of the ISA, HREA, and/or PA. The CASAC O_3 Panel reviewed the interpretation of the evidence, and the EPA's use of information from specific studies, in drafts of these documents. In CASAC's advice to the Administrator, which incorporates its consideration of many of the issues raised by commenters, CASAC approved of the scientific content, assessments, and accuracy of the ISA, REA, and PA, and indicated that these documents provide an appropriate basis for use in regulatory decision making for the O_3 NAAQS (Frey and Samet, 2012, Frey, 2014a, Frey, 2014c). Therefore, the EPA's responses to many of the comments on the evidence rely heavily on the process established in the ISA for assessing the evidence, which is the product of extensive interactions with CASAC over a number of different reviews, and on CASAC advice received as part of this review of the O_3 NAAQS.

The remainder of this section discusses public comments and the EPA's responses, on controlled human exposure studies (II.B.2.b.i); epidemiologic studies (II.B.2.b.ii); and at-risk populations (II.B.2.b.iii).

i. Evidence From Controlled Human Exposure Studies

This section discusses major comments on the evidence from controlled human exposure studies and provides the Agency's responses to those comments. To support their views on the adequacy of the current standard, commenters often highlighted specific aspects of the scientific evidence from controlled human exposure studies. Key themes discussed by these commenters included the following: (1) The adversity of effects demonstrated in controlled human exposure studies, especially studies conducted at exposure concentrations below 80 ppb; (2) representativeness of different aspects of the controlled human exposure studies for making inferences to the general population and at-risk populations; (3) results of additional analyses of the data from controlled human exposure studies; (4) evaluation of a threshold for effects; and (5) importance of demonstration of inflammation at 60 ppb. This section discusses these key comment themes, and provides the EPA's responses. More detailed discussion of individual comments, and the EPA's responses, is provided in the Response to Comments document.

Adversity

Some commenters who disagreed with the EPA's proposed decision to revise the current primary O_3 standard disputed the Agency's characterization

[87] As discussed in section I.C above, the EPA has provisionally considered studies that were highlighted by commenters and that were published after the ISA. These studies are generally consistent with the evidence assessed in the ISA, and they do not materially alter our understanding of the scientific evidence or the Agency's conclusions based on that evidence.

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of the adversity of the O_3-induced health effects shown to occur in controlled human exposure studies. Some of these commenters contended that the proposal does not provide a clear definition of adversity or that there is confusion concerning what responses the Administrator considers adverse. The EPA disagrees with these comments, and notes that section II.E.4.d of the proposal describes the Administrator's proposed approach to considering the adversity of effects observed in controlled human exposure studies. Her final approach to considering the adversity of these effects, and her conclusions on adversity, are described in detail below (II.C.4.b, II.C.4.c).

Other commenters disagreed with the EPA's judgments regarding adversity and expressed the view that the effects observed in controlled human exposure studies following 6.6-hour exposures to O_3 concentrations below the level of the current standard (*i.e.,* 75 ppb) are not adverse.[88] This group of commenters cited several reasons to support their views, including that: (1) The lung function decrements and respiratory symptoms observed at 72 ppb in the study by Schelegle et al. (2009) were not correlated with each other, and therefore were not adverse; and (2) group mean FEV_1 decrements observed following exposures below 75 ppb are small (*e.g.,* <10%, as highlighted by some commenters), transient and reversible, do not interfere with daily activities, and do not result in permanent respiratory injury or progressive respiratory dysfunction.

While the EPA agrees that not all effects reported in controlled human exposure studies following exposures below 75 ppb can reasonably be considered to be adverse, the Agency strongly disagrees with comments asserting that none of these effects can be adverse. As an initial matter, the Administrator notes that, when considering the extent to which the current or a revised standard could allow adverse respiratory effects, based on information from controlled human exposure studies, she considers not only the effects themselves, but also quantitative estimates of the extent to which the current or a revised standard could allow such effects. Quantitative exposure and risk estimates provide perspective on the extent to which various standards could allow populations, including at-risk populations such as children and children with asthma, to experience the types of O_3 exposures that have been shown in controlled human exposure studies to cause respiratory effects. As discussed further below (II.B.3, II.C.4.b, II.C.4.c), to the extent at-risk populations are estimated to experience such exposures repeatedly, the Administrator becomes increasingly concerned about the potential for adverse responses in the exposed population. Repeated exposures provide a plausible mode of action by which O_3 may cause other more serious effects. Thus, even though the Administrator concludes there is important uncertainty in the adversity of some of the effects observed in controlled human exposure studies based on the single exposure periods evaluated in these studies (*e.g.,* FEV_1 decrements observed following exposures to 60 ppb O_3, as discussed in sections II.C.4.b and II.C.4.c below), she judges that the potential for adverse effects increases as the number of exposures increases. Contrary to the commenters' views noted above, the Administrator considers the broader body of available information (*i.e.,* including quantitative exposure and risk estimates) when considering the extent to which the current or a revised standard could allow adverse respiratory effects (II.B.3, II.C.4.b, II.C.4.c, below).

In further considering commenters' views on the potential adversity of the respiratory effects themselves (*i.e.,* without considering quantitative estimates), the EPA notes that although the results of controlled human exposure studies provide a high degree of confidence regarding the occurrence of health effects following exposures to O_3 concentrations from 60 to 80 ppb, there are no universally accepted criteria by which to judge the adversity of the observed effects. Therefore, as in the proposal, the Administrator relies upon recommendations from the ATS and advice from CASAC to inform her judgments on adversity.

In particular, the Administrator focuses on the ATS recommendation that ''reversible loss of lung function in combination with the presence of symptoms should be considered adverse'' (ATS, 2000a). The study by Schelegle et al. (2009) reported a statistically significant decrease in group mean FEV_1 and a statistically significant increase in respiratory symptoms in healthy adults following 6.6-hour exposures to average O_3 concentrations of 72 ppb. In considering these effects, CASAC noted that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5).

As mentioned above, some commenters nonetheless maintained that the effects observed in Schelegle et al. (2009) following exposure to 72 ppb O_3 (average concentration) were not adverse because the magnitudes of the FEV_1 decrements and the increases in respiratory symptoms (as measured by the total subjective symptoms score, TSS) were not correlated across individual study subjects. A commenter submitted an analysis of the individual-level data from the study by Schelegle et al. (2009) to support their position. This analysis indicated that, while the majority of study volunteers (66%) did experience both lung function decrements and increased respiratory symptoms following 6.6-hour exposures to 72 ppb O_3, some (33%) did not (*e.g.,* Figure 3 in comments from Gradient).[89] In addition, the study subjects who experienced relatively large lung function decrements did not always also experience relatively large increases in respiratory symptoms. These commenters interpreted the lack of a statistically significant correlation between the magnitudes of decrements and symptoms as meaning that the effects reported by Schelegle et al. (2009) at 72 ppb did not meet the ATS criteria for an adverse response.

However, the ATS recommendation that the combination of lung function decrements and symptomatic responses be considered adverse is not restricted to effects of a particular magnitude nor a requirement that individual responses be correlated. Similarly, CASAC made no such qualifications in its advice on the combination of respiratory symptoms and lung function decrements (See *e.g.,* Frey, 2014c, p. 5). Therefore, as in the proposal and consistent with both CASAC advice and ATS recommendations, the EPA continues to conclude that the finding of both statistically significant decrements in lung function and significant increases in respiratory symptoms following 6.6-hour exposures to an average O_3 concentration of 72 ppb provides a strong indication of the

[88] Commenters who supported revising the primary O_3 standard often concluded that there is clear evidence for adverse effects following exposures to O_3 concentrations at least as low as 60 ppb, and that such adverse effects support setting the level of a revised primary O_3 standard at 60 ppb. These comments, and the EPA's responses, are discussed below within the context of the Administrator's decision on a revised level (II.C.4.b).

[89] The figure provided in comments by Gradient only clearly illustrated the responses of 30 out of 31 subjects.

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potential for exposed individuals to experience this combination of effects.[90]

In particular, the Administrator notes that lung function provides an objective measure of the respiratory response to O_3 exposure while respiratory symptoms are subjective, and as evaluated by Schelegle et al. (2009) were based on a TSS score. If an O_3 exposure causes increases in both objectively measured lung function decrements and subjective respiratory symptoms, which indicate that people may modify their behavior in response to the exposure, then the effect is properly viewed as adverse. As noted above, the commenter's analysis shows that the majority of study volunteers exposed to 72 ppb O_3 in the study by Schelegle et al. (2009) did, in fact, experience both a decrease in lung function and an increase in respiratory symptoms.

In further considering this comment, the EPA recognizes that, consistent with commenter's analysis, some individuals may experience large decrements in lung function with minimal to no respiratory symptoms (McDonnell et al., 1999), and vice versa. As indicated above and discussed in the proposal (79 FR 75289), the Administrator acknowledges such interindividual variability in responsiveness in her interpretation of estimated exposures of concern. Specifically, she notes that not everyone who experiences an exposure of concern, including for the 70 ppb benchmark, is expected to experience an adverse response. However, she further judges that the likelihood of adverse effects increases as the number of occurrences of O_3 exposures of concern increases. In making this judgment, she notes that the types of respiratory effects that can occur following exposures of concern, particularly if experienced repeatedly, provide a plausible mode of action by which O_3 may cause other more serious effects.[91] Therefore, her decisions on the primary standard emphasize the public health importance of limiting the occurrence of repeated exposures to O_3 concentrations at or above those shown to cause adverse effects in controlled human exposure studies (II.B.3, II.C.4.b, II.C.4.c). The Administrator views this approach to considering the evidence from controlled human exposure studies as being consistent with commenter's analysis indicating that, while the majority did, not all study volunteers exposed to 72 ppb O_3 experienced the adverse combination of lung function decrements and respiratory symptoms following the single exposure period evaluated by Schelegle et al. (2009).

Representativeness

A number of commenters raised issues concerning the representativeness of controlled human exposure studies considered by the Administrator in this review, based on different aspects of these studies. These commenters asserted that since the controlled human exposure studies were not representative of real-world exposures, they should not be relied upon as a basis for finding that the current standard is not adequate to protect public health. Some issues highlighted by commenters include: Small size of the study populations; unrealistic activity levels used in the studies; unrealistic exposure scenarios (*i.e.,* triangular exposure protocol) used in some studies, including Schelegle et al. (2009); and differences in study design that limit comparability across studies.

Some commenters noted that the controlled human exposure studies were not designed to have individuals represent portions of any larger group and that the impacts on a small number of people do not implicate the health of an entire subpopulation, particularly when the FEV_1 decrements are small, temporary, and reversible. These commenters also noted that the Administrator failed to provide an explanation or justification for why the individuals in these studies can be viewed as representatives of a subpopulation. Further, they asserted that EPA's use of results from individuals, rather than the group mean responses, contradicts the intent of CAA section 109 to protect groups of people, not just the most sensitive individuals in any group (79 FR 75237).

Consistent with CASAC advice (Frey, 2014c, p. 5), the EPA concludes that the body of controlled human exposure studies are sufficiently representative to be relied upon as a basis for finding that the current standard is not adequate to protect public health. These studies generally recruit healthy young adult volunteers, and often expose them to O_3 concentrations found in the ambient air under real-world exposure conditions. As described in more detail above in section II.A.1.b, the evidence from controlled human exposure studies to date makes it clear that there is considerable variability in responses across individuals, even in young healthy adult volunteers, and that group mean responses are not representative of more responsive individuals. It is important to look beyond group mean responses to the responses of these individuals to evaluate the potential impact on more responsive members of the population. Moreover, relying on group mean changes to evaluate lung function responses to O_3 exposures would mask the responses of the most sensitive groups, particularly where, as here, the group mean reflects responses solely among the healthy young adults who were the study participants. Thus, the studies of exposures below 80 ppb O_3 show that 10% of young healthy adults experienced FEV_1 decrements >10% following exposures to 60 ppb O_3, and 19% experienced such decrements following exposures to 72 ppb (under the controlled test conditions involving moderate exertion for 6.6 hours). These percentages would likely have been higher had people with asthma or other at-risk populations been exposed (U.S. EPA, 2013, pp. 6–17 and 6–18; Frey 2014c, p. 7; Frey, 2014a, p. 14).[92]

Moreover, the EPA may legitimately view the individuals in these studies as representatives of the larger subpopulation of at-risk or sensitive groups. As stated in the Senate Report to the 1970 legislation establishing the NAAQS statutory provisions, ''the Committee emphasizes that included among these persons whose health should be protected by the ambient standard are particularly sensitive citizens such as bronchial asthmatics and emphysematics who in the normal course of daily activity are exposed to the ambient environment. In establishing an ambient standard necessary to protect the health of these persons, reference should be made to a representative sample of persons comprising the sensitive group rather than to a single person in such a group .... For purposes of this description, a statistically related sample is the number of persons necessary to test in order to detect a deviation in the health of any person within such sensitive group which is attributable to the condition of the ambient air.'' S. Rep. No. 11–1196, 91st

[90] Indeed, the finding of statistically significant decreases in lung function and increases in respiratory symptoms in the same study population indicates that, on average, study volunteers did experience both effects.

[91] For example, as discussed in the proposal (79 FR 75252) and the ISA (p. 6–76), inflammation induced by a single exposure (or several exposures over the course of a summer) can resolve entirely. However, repeated occurrences of airway inflammation could potentially result in the induction of a chronic inflammatory state; altered pulmonary structure and function, leading to diseases such as asthma; altered lung host defense response to inhaled microorganisms; and altered lung response to other agents such as allergens or toxins (ISA, section 6.2.3).

[92] See also *National Environmental Development Associations Clean Action Project* v. *EPA,* 686 F. 3d 803, 811 (D.C. Cir. 2012) (EPA drew legitimate inference that serious asthmatics would experience more serious health effects than clinical test subjects who did not have this degree of lung function impairment).

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Cong. 2d sess. at 10. As just noted above, 10% of healthy young adults in these studies experienced >10% FEV_1 decrements following exposure to 60 ppb O_3, and the proportion of individuals experiencing such decrements increases with increasing O_3 exposure concentrations. This substantial percentage certainly can be viewed as ''a representative sample of persons'' and as a sufficient number to ''detect a deviation in the health of any person within such sensitive group,'' especially given that it reflects the percentage of *healthy adults* who experienced decrements >10%.

These results are consistent with estimates from the MSS model, which makes reliable quantitative predictions of the lung function response to O_3 exposures, and reasonably predicts the magnitude of individual lung function responses following such exposures. As described in section II.A.2.c above, and documented in the HREA, when the MSS model was used to quantify the risk of O_3-induced FEV_1 decrements in 15 urban study areas, the current standard was estimated to allow about 8 to 12% of children to experience two or more O_3-induced FEV_1 decrements ≥10%, and about 2 to 3% to experience two or more decrements ≥15% (Table 2, above). These percentages correspond to hundreds of thousands of children in urban study areas, and tens of thousands of asthmatic children. While the Administrator judges that there is uncertainty with regard to the adversity of these O_3-induced lung function decrements (see II.C.4.b, II.C.4.c, below), such risk estimates clearly indicate that they are a matter of public health importance on a broad scale, not isolated effects on idiosyncratically responding individuals.

Other commenters considered the ventilation rates used in controlled human exposure studies to be unreasonably high and at the extreme of prolonged daily activity. Some of these commenters noted that these scenarios are unrealistic for sensitive populations, such as asthmatics and people with COPD, whose conditions would likely prevent them from performing the intensity of exercise, and therefore experiencing the ventilation rates, required to produce decrements in lung function observed in experimental settings.

The EPA disagrees with these commenters. The activity levels used in controlled human exposure studies were summarized in Table 6–1 of the ISA (U.S. EPA, 2013). The exercise level in the 6.6-hour exposure studies by Adams (2006), Schelegle et al. (2009), and Kim et al. (2011) of young healthy adults was moderate and ventilation rates are typically targeted for 20 L/min-m^2 BSA.[93] Following the exposures to 60 ppb at this activity level, 10% of the individuals had greater than a 10% decrement in FEV_1 (U.S. EPA, 2013, p. 6–18). Similar 6.6-hour exposure studies of individuals with asthma are not available to assess either the effects of O_3 on their lung function or their ability to perform the required level of moderate exercise.

However, referring to Tables 6–9 and 6–10 of the HREA (U.S. EPA, 2014a), between 42% and 45% of FEV_1 decrements ≥ 10% were estimated to occur at exercise levels of <13 L/min-m^2 BSA. This corresponds to light exercise, and this level of exercise has been used in a 7.6-hour study of healthy people and people with asthma exposed to 160 ppb O_3 (Horstman et al., 1995). In that study, people with asthma exercised with an average minute ventilation of 14.2 L/min-m^2 BSA. Adjusted for filtered air responses, an average 19% FEV_1 decrement was seen in the people with asthma versus an average 10% FEV_1 decrement in the healthy people. In addition, the EPA noted in the HREA that the data underlying the exposure assessment indicate that ''activity data for asthmatics [is] generally similar to [that for] non-asthmatics'' (U.S. EPA, 2014a, p. 5–75, Tables 5G–2 and 5G–3). Thus, contrary to the commenters' assertion, based on both the HREA and the Horstman et al. (1995) study, people with respiratory disease such as asthma can exercise for a prolonged period under conditions where they would experience >10% FEV_1 decrements in response to O_3 exposure.

Additionally, a number of commenters asserted that the exposure scenarios in Schelegle et al. (2009), which are based on a so-called triangular study protocol, where O_3 concentrations ramp up and down as the study is conducted, are not directly generalizable to most healthy or sensitive populations because of large changes in the O_3 concentrations from one hour to the next. Commenters stated that although large fluctuations in O_3 are possible in certain locations due to meteorological conditions (*e.g.,* in valleys on very hot, summer days), they believe that, in general, concentrations of O_3 do not fluctuate by more than 20–30 ppb from one hour to the next. Thus, commenters suggested the Schelegle et al. (2009) study design could happen in a ''worst-case'' exposure scenario, but that the exposure protocol was not reflective of conditions in most cities and thus not informative with regard to the adequacy of the current standard.

The EPA disagrees with the comment that these triangular exposure scenarios are not generalizable because of hour-to-hour fluctuations. Adams (2002, 2006) showed that FEV_1 responses following 6.6 hours of exposure to 60 and 80 ppb average O_3 exposures do not differ between triangular (*i.e.* ramping concentration up and down) and square-wave (*i.e.* constant concentration). Schelegle et al. (2009) used the 80 ppb triangular protocol and a slightly modified 60 ppb triangular protocol (concentrations during the third and fourth hours were reversed) from Adams (2006). Therefore, in considering pre- to post-exposure changes in lung function, concerns about the hour-by-hour changes in O_3 concentrations at 60 and 80 ppb in the Schelegle et al. (2009) study are unfounded.

Finally, some commenters also stated that the Kim et al. (2011) study is missing critical information and its study design makes comparison to the other studies difficult. That is, the commenter suggests that data at times other than pre- and post-exposure should have been provided.

The EPA disagrees with this comment. With regard to providing data at other time points besides pre- and post-exposure, there is no standard that suggests an appropriate frequency at which lung function should be measured in prolonged 6.6-hour exposure studies. The Adams (2006) study showed that lung function decrements during O_3 exposures with moderate exercise become most apparent following the third hour of exposure. As such, it makes little sense to measure lung function during the first couple hours of exposure. However, having data at multiple time points toward the end of an exposure can provide evidence that the mean post-exposure FEV_1 response is not a single anomalous data point. The FEV_1 response data for the 3-, 4.6-, 5.6-, and 6.6-hour time points of the Kim et al. (2011) study are available in Figure 6 of the McDonnell et al. (2012) paper where they are plotted with the Adams (2006) data for 60 ppb. Similar to the Adams (2006) study, the responses at 5.6 hours are only marginally smaller than the response at 6.6 hours in the Kim et al. (2011) study. This indicates that the post-exposure FEV_1 responses in both studies are consistent with responses at an earlier time point and thus not likely to be anomalous data.

[93] Exercise consisted of alternating periods walking on a treadmill at a pace of 17–18 minutes per mile inclined to a grade of 4–5% or cycling at a load of about 72 watts. Typical heart rates during the exercise periods were between 115–130 beats per minute. This activity level is considered moderate (Table 6–1, U.S. EPA, 2013, p. 6–18).

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Additional Studies

Several commenters analyzed the data from controlled human exposure studies, or they commented on the EPA's analysis of the data from some of these studies (Brown et al., 2008), to come to a different conclusion than the EPA's interpretation of these studies thereby questioning the proposed decision that the current standard is not adequate to protect public health. One commenter submitted an independent assessment of the scientific evidence and risk, and used this analysis to assert that there are multiple flaws in the underlying studies and their interpretation by the EPA. This commenter stated that the EPA's discussion of the spirometric responses of children and adolescents and older adults to O_3 was misleading. They claimed that the EPA did not mention that ''the responses of children and adolescents are equivalent to those of young adults (18–35 years old; McDonnell et al., 1985) and that this response diminishes in middle-aged and older adults (Hazucha 1985).'' The EPA notes that the commenter misrepresented our characterization of the effect of age on FEV_1 responses to O_3 and asserted mistakenly that EPA did not mention diminished responses on older adults. In fact, the proposal clearly states that, ''Respiratory symptom responses to O_3 exposure appears to increase with age until early adulthood and then gradually decrease with increasing age (U.S. EPA, 1996b); lung function responses to O_3 exposure also decline from early adulthood (U.S. EPA, 1996b)'' (79 FR 75267) (see also U.S. EPA, 2014c p. 3–82). With regard to differences between children and adults, it was clearly stated in the ISA (U.S. EPA, 2013, p. 6–21) that healthy children exposed to filtered air and 120 ppb O_3 experienced similar spirometric responses, but lesser symptoms than similarly exposed young healthy adults (McDonnell et al., 1985). In addition, the EPA's approach to modeling the effect of age on responses to O_3 is clearly provided in the HREA (U.S. EPA, 2014a, Table 6–2).

The commenter also stated that the EPA's treatment of filtered air responses in the dose-response curve was incorrect. They claimed that when creating a dose-response curve, it is most appropriate to include a zero-dose point and not to subtract the filtered air response from responses to O_3. Contrary to this assertion, EPA correctly adjusted FEV_1 responses to O_3 by responses following filtered air, as was also done in the McDonnell et al. (2012) model. As indicated in the ISA (U.S. EPA, 2013, p. 6–4), the majority of controlled human exposure studies investigating the effects O_3 are of a randomized, controlled, crossover design in which subjects were exposed, without knowledge of the exposure condition and in random order, to clean filtered air and, depending on the study, to one or more O_3 concentrations. The filtered air control exposure provides an unbiased estimate of the effects of the experimental procedures on the outcome(s) of interest. Comparison of responses following this filtered air exposure to those following an O_3 exposure allows for estimation of the effects of O_3 itself on an outcome measurement while controlling for independent effects of the experimental procedures, such as ventilation rate. Thus, the commenter's approach does not provide an estimate of the effects of O_3 alone. Furthermore, as illustrated in these comments, following ''long'' filtered air exposures, there is about a 1% improvement in FEV_1. By not accounting for this increase in FEV_1, the commenter underestimated the FEV_1 decrement due to O_3 exposure. The commenter's approach thus is fundamentally flawed.

The commenter also asserted that the McDonnell et al. (2012) model and exposure-response (E–R) models incorrectly used only the most responsive people and that EPA's reliance on data from clinical trials that use only the most responsive people irrationally ignores large portions of relevant data. The EPA rejects this assertion that the McDonnell et al. (2012) model and the E–R analysis ignored large portions of relevant data. The McDonnell et al. (2012) model was fit to the FEV_1 responses of 741 individuals to O_3 and filtered air (*i.e.,* reflecting all available data for O_3-induced changes in FEV_1). The filtered air responses were subtracted from responses measured during O_3 exposures. Subsequently, as illustrated by the figures in the McDonnell et al. (2012) paper and described in the text of paper, the model was fit to all available FEV_1 data measured during the course of O_3 exposures, including exposures shorter than 6.6 hours. Thus, the model predicts temporal dynamics of FEV_1 response to any set of O_3 exposure conditions that might reasonably be experienced in the ambient environment, predicting the mean responses and the distribution of responses around the mean. For the HREA (EPA, 2014a), the proportion of individuals, under variable exposure conditions, predicted to have FEV_1 decrements ≥10, 15 and 20% was estimated.

Finally, the commenter referenced the exposure-response model on p. 6–18 of the HREA. However, they neglected to note that this was in a section describing the exposure-response function approach used in prior reviews (U.S. EPA, 2014a, starting on p. 6–17). Thus, the commenter confused the exposure-response model used in the last review with the updated approach used in this review.

The commenter also stated that EPA did not properly consider O_3 dose when interpreting the human clinical data. Ozone total dose includes three factors: duration of exposure, concentration, and ventilation rate. The commenter claimed the EPA emphasized only concentration without properly considering and communicating duration of exposure and ventilation rate. Further, they asserted that because people are not exposed to the same dose, they cannot be judged to have the same exposure and would therefore not be expected to respond consistently. The EPA rejects the claim that we emphasized only concentration without properly incorporating the other two factors. As noted in the ISA, total O_3 dose does not describe the temporal dynamics of FEV_1 responses as a function of concentration, ventilation rate, time and age of the exposed individuals (U.S. EPA, 2013, p. 6–5). Thus, the use of total O_3 dose is antiquated and the EPA therefore conducted a more sophisticated analysis of FEV_1 response to O_3 in the HREA. In this review, the HREA estimates risks of lung function decrements in school-aged children (ages 5 to 18), asthmatic school-aged children, and the general adult population for 15 urban study areas. A probabilistic model designed to account for the numerous sources of variability that affect people's exposures was used to simulate the movement of individuals through time and space and to estimate their exposure to O_3 while occupying indoor, outdoor, and in-vehicle locations. That information was linked with the McDonnell et al. (2012) model to estimate FEV_1 responses over time as O_3 exposure concentrations and ventilation rates changed. As noted earlier, CASAC agreed that this approach is both scientifically valid and a significant improvement over approaches used in past O_3 reviews (Frey, 2014a, p. 2).

Several commenters criticized the EPA analysis published by Brown et al. (2008). One commenter suggested that the EPA needed to state why the Brown et al. (2008) analysis was relied on rather than Nicolich (2007) or Lefohn et

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al. (2010). Further, commenters stated that the analysis of the Adams (2006) data in Brown et al. (2008) was flawed. Among other reasons, one commenter expressed the opinion that it was not appropriate for Brown et al. (2008) to only examine a portion of the Adams (2006) data, citing comments submitted by Gradient.

The EPA disagrees with these commenters.[94] As an initial matter, Nicolich (2007) was a public comment and is not a peer-reviewed publication that would be used to assess the scientific evidence for effects of O_3 on lung function in the ISA (U.S. EPA, 2013). The Nicolich (2007) comments were specifically addressed by the EPA on pp. 24–25 in the Response to Comments Document for the 2007 proposed rule (U.S. EPA, 2008). On page A–3 of his comments, Dr. Nicolich stated ''that the residuals are not normally distributed and the observations do not meet the assumptions required for the model'' and that ''the subject-based errors are not independently, identically and normally distributed and the subjects do not meet the assumptions required for the model.'' The EPA reasonably chose not to rely on this analysis: ''Therefore, given that the underlying statistical assumptions required for his analyses were not met and that significance levels are questionable, in EPA's judgment the analyses presented by Dr. Nicolich are ambiguous'' (U.S. EPA, 2008). It is likely that the Lefohn et al. (2010) analysis of the Adams (2006) data would similarly not meet the statistical assumptions of the model (*e.g.,* homoscedasticity). In contrast, recognizing the concerns related to the distribution of responses, Brown et al. (2008) conservatively used a nonparametric sign test to obtain a p-value of 0.002 for the comparison responses following 60 ppb O_3 versus filter air. Other common statistical tests also showed significant effects on lung function. In addition, the effects of 60 ppb O_3 on FEV_1 responses in Brown et al. (2008) remained statistically significant even following the exclusion of three potential outliers.

EPA disagrees with the comment stating that it was not appropriate for Brown et al. (2008) to only examine a portion of the Adams (2006) data. In fact, there is no established single manner or protocol decreeing that data throughout the protocol must be analyzed and included. Furthermore, Brown et al. (2008) was a peer-reviewed journal publication. CASAC also expressed favorable comments in their March 30, 2011, letter to Administrator Jackson. With reference to a memorandum (Brown, 2007) that preceded the Brown et al. (2008) publication, on p. 6 of the CASAC Consensus Responses to Charge Questions CASAC stated, ''The results of the Adams et al. study also have been carefully reanalyzed by EPA investigators (Brown et. al., [2008]), and this reanalysis showed a statistically significant group effect on FEV_1 after 60 ppb ozone exposure.'' On p. A–13, a CASAC panelist and biostatistician stated, ''Thus, from my understanding of the statistical analyses that have been conducted, I would argue that the analysis by EPA should be preferred to that of Adams for the specific comparison of the FEV_1 effects of 0.06 ppm exposure relative to filtered air exposure.'' (Samet 2011, p. a-13)

Threshold

Several commenters used the new McDonnell et al. (2012) and Schelegle et al. (2012) models to support their views about the O_3 concentrations associated with a threshold for adverse lung function decrements. For example, one commenter who supported retaining the current standard noted that McDonnell et al. (2012) found that the threshold model fit the observed data better than the original (no-threshold) model, especially at earlier time points and at the lowest exposure concentrations. The commenter expressed the view that the threshold model showed that the population mean FEV_1 decrement did not reach 10% until exposures were at least 80 ppb, indicating that O_3 exposures of 80 ppb or higher may cause lung function decrements and other respiratory effects.[95]

As described above in section II.A.1.b, the McDonnell et al. (2012) and Schelegle et al. (2012) models represent a significant technological advance in the exposure-response modeling approach since the last review, and these models indicate that a dose-threshold model fits the data better than a non-threshold model. However, the EPA disagrees that using the predicted group mean response from the McDonnell model provides support for retaining the current standard. As discussed above, the group mean responses do not convey information about interindividual variability, or the proportion of the population estimated to experience the larger lung function decrements (*e.g.,* 10 or 15% FEV_1 decrements) that could be adverse. In fact, it masks this variability. These variable effects in individuals have been found to be reproducible. In other words, a person who has a large lung function response after exposure to O_3 will likely have about the same response if exposed again in a similar manner (raising health concerns, as noted above). Group mean responses are not representative of this segment of the population that has much larger than average responses to O_3.

Inflammation

Some commenters asserted that the pulmonary inflammation observed following exposure to 60 ppb in the controlled human exposure study by Kim et al. (2011) was small and unlikely to result in airway damage. It was also suggested that this inflammation is a normal physiological response in all living organisms to stimuli to which people are normally exposed.

The EPA recognized in the proposal (79 FR 75252) and the ISA (U.S. EPA, 2013, p. 6–76) that inflammation induced by a single exposure (or several exposures over the course of a summer) can resolve entirely. Thus, the inflammatory response observed following the single exposure to 60 ppb in the study by Kim et al. (2011) is not necessarily a concern. However, the EPA notes that it is also important to consider the potential for continued acute inflammatory responses to evolve into a chronic inflammatory state and to affect the structure and function of the lung.[96] The Administrator considers this possibility through her consideration of estimated exposures of concern for the 60 ppb benchmark (II.B.3, II.C.4). As discussed in detail below (II.C.4.b), while she judges that there is uncertainty in the adversity of the effects shown to occur following exposures to 60 ppb O_3, including the inflammation reported by Kim et al.

[94] The DC Circuit has held that EPA reasonably used and interpreted the Brown (2007) study in the last review. *Mississippi,* 744 F. 3d at 1347. In this review, there is now additional corroborative evidence supporting the Brown (2007) analysis, in the form of further controlled human clinical studies finding health effects in young, healthy adults at moderate exercise at O_3 concentrations of 60 ppb over a 6.6 hour exposure period.

[95] Conversely, another group of commenters who supported revising the standard to a level of 60 ppb noted that the results of these models are consistent with the results of controlled human exposure studies finding adverse health effects at 60 ppb. These comments are discussed below (II.C.4.b), within the context of the Administrator's decision on a revised standard level.

[96] Inflammation induced by exposure of humans to O_3 can have several potential outcomes, ranging from resolving entirely following a single exposure to becoming a chronic inflammatory state (U.S. EPA, 2013, section 6.2.3). Lung injury and the resulting inflammation provide a mechanism by which O_3 may cause other more serious morbidity effects (*e.g.,* asthma exacerbations) (U.S. EPA, 2013, section 6.2.3). See generally section II.A.1.a above.

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(2011), she gives some consideration to estimates of two or more exposures of concern for the 60 ppb benchmark (*i.e.,* as a health-protective surrogate for repeated exposures of concern at or above 60 ppb), particularly when considering the extent to which the current and revised standards incorporate a margin of safety.

ii. Evidence Fom epidemiologic studies

This section discusses key comments on the EPA's assessment of the epidemiologic evidence and provides the Agency's responses to those comments. The focus in this section is on overarching comments related to the EPA's approach to assessing and interpreting the epidemiologic evidence as a whole. Detailed comments on specific studies, or specific methodological or technical issues, are addressed in the Response to Comments document. As discussed above, many of the issues and concerns raised by commenters on the interpretation of the epidemiologic evidence are essentially restatements of issues raised during the development of the ISA, HREA, and/or PA, and in many instances were considered by CASAC in the development of its advice on the current standard. The EPA's responses to these comments rely heavily on the process established in the ISA for assessing the evidence, and on CASAC advice received as part of this review of the O_3 NAAQS.

As with evidence from controlled human exposure studies, commenters expressed sharply divergent views on the evidence from epidemiologic studies, and on the EPA's interpretation of that evidence. One group of commenters, representing medical, public health and environmental organizations, and some states, generally supported the EPA's interpretation of the epidemiologic evidence with regard to the consistency of associations, the coherence with other lines of evidence, and the support provided by epidemiologic studies for the causality determinations in the ISA. These commenters asserted that the epidemiologic studies evaluated in the ISA provide valuable information supporting the need to revise the level of the current primary O_3 standard in order to increase public health protection. In reaching this conclusion, commenters often cited studies (including a number from the past review) which they interpreted as showing health effect associations in locations with O_3 air quality concentrations below the level of the current standard. A second group of commenters, mostly representing industry associations, businesses, and states opposed to revising the primary O_3 standard, expressed the general view that while many new epidemiologic studies have been published since the last review of the O_3 NAAQS, inconsistencies and uncertainties inherent in these studies as a whole, and in the EPA's assessment of study results, should preclude any reliance on them as justification for a more stringent primary O_3 standard. To support their views, these commenters often focused on specific technical or methodological issues that contribute to uncertainty in epidemiologic studies, including the potential for exposure error, confounding by copollutants and by other factors (*e.g.,* weather, season, disease, day of week, etc.), and heterogeneity in results across locations.

The EPA agrees with certain aspects of each of these views. Specifically, while the EPA agrees that epidemiologic studies are an important part of the broader body of evidence that supports the ISA's causality determinations, and that these studies provide support for the decision to revise the current primary O_3 standard, the Agency also acknowledges that there are important uncertainties and limitations associated with these epidemiologic studies that should be considered when reaching decisions on the current standard. Thus, although these studies show consistent associations between O_3 exposures and serious health effects, including morbidity and mortality, and some of these studies reported such associations with ambient O_3 concentrations below the level of the current standard, there are also uncertainties regarding the ambient O_3 concentrations in critical studies, such that they lend only limited support to establishing a specific level for a revised standard. (See generally, *Mississippi,* 744 F. 3d at 1351 (noting that in prior review, EPA reasonably relied on epidemiologic information in determining to revise the standard but appropriately gave the information limited weight in determining a level of a revised standard); see also *ATA III,* 283 F. 3d at 370 (EPA justified in revising NAAQS when health effect associations are observed in epidemiologic studies at levels allowed by the current NAAQS); *Mississippi,* 744 F. 3d at 1345 (same)).

Uncertainties in the evidence were considered by the Administrator in the proposal, and contributed to her decision to place less weight on information from epidemiologic studies than on information from controlled human exposure studies when considering the adequacy of the current primary O_3 standard (see 79 FR 75281–83). Despite receiving less weight in the proposal, the EPA does not agree with commenters who asserted that uncertainties in the epidemiologic evidence provide a basis for concluding that the current primary standard does not need revision. The Administrator specifically considered the extent to which available studies support the occurrence of O_3 health effect associations with air quality likely to be allowed by the current standard, while also considering the implications of important uncertainties, as assessed in the ISA and discussed in the PA. This consideration is consistent with CASAC comments on consideration of these studies in the draft PA (Frey, 2014c, p. 5).

Based on analyses of study area air quality in the PA, the EPA notes that most of the U.S. and Canadian epidemiologic studies evaluated were conducted in locations likely to have violated the current standard over at least part of the study period. Although these studies support the ISA's causality determinations, they provide limited insight into the adequacy of the public health protection provided by the current primary O_3 standard. However, as discussed in the proposal, air quality analyses in the locations of three U.S. single-city studies provide support for the occurrence of O_3-associated hospital admissions or emergency department visits at ambient O_3 concentrations below the level of the current standard.[97] Specifically, a U.S. single-city study reported associations with respiratory emergency department visits in children and adults in a location that would have met the current O_3 standard over the entire study period (Mar and Koenig, 2009). In addition, for two studies conducted in locations where the current standard was likely not met (*i.e.,* Silverman and Ito, 2010; Strickland et al., 2010), PA analyses indicate that reported concentration-response functions and available air quality data support the occurrence of O_3-health effect associations on subsets of days with virtually all monitored ambient O_3 concentrations below the level of the current standard (U.S. EPA, 2014c,

[97] As discussed in section II.E.4.d of the proposal, is the Administrator noted the greater uncertainty in using analyses of short-term O_3 air quality in locations of the multicity studies in this review to inform decisions on the primary O_3 standard. This is because the health information in these studies cannot be disaggregated by individual city. Thus, the multicity effect estimates reported in these studies do not provide clear indication of the extent to which health effects are associated with the ambient O_3 concentrations in the study locations that met the current O_3 standard, versus the ambient O_3 concentrations in the study locations that violated the standard.

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section 3.1.4.2, pp. 3–66 to 67).[98] Thus, the EPA notes that a small number of O_3 epidemiologic studies provide support for the conclusion that the current primary standard is not requisite, and that it should be revised to increase public health protection.

As part of a larger set of comments criticizing the EPA's interpretation of the evidence from time series epidemiologic studies, some commenters objected to the EPA's reliance on the studies by Strickland et al. (2010), Silverman and Ito (2010), and Mar and Koenig (2009). These commenters highlighted what they considered to be key uncertainties in interpreting these studies, including uncertainties due to the potential for confounding by co-pollutants, aeroallergens, or the presence of upper respiratory infections; and uncertainties in the interpretation of zero-day lag models (*i.e.,* specifically for Mar and Koenig, 2009).

While the EPA agrees that there are uncertainties associated with interpreting the O_3 epidemiologic evidence, as discussed above and elsewhere in this preamble, we disagree with commenters' assertion that these uncertainties should preclude the use of the O_3 epidemiologic evidence in general, or the studies by Silverman and Ito, Strickland, or Mar and Koenig in particular, as part of the basis for the Administrator's decision to revise the current primary standard. As a general point, when considering the potential importance of uncertainties in epidemiologic studies, we rely on the broader body of evidence, not restricted to these three studies, and the ISA conclusions based on this evidence. The evidence, the ISA's interpretation of specific studies, and the use of information from these studies in the HREA and PA, was considered by CASAC in its review of drafts of the ISA, HREA, and PA. Based on the assessment of the evidence in the ISA, and CASAC's endorsement of the ISA conclusions, as well as CASAC's endorsement of the approaches to using and considering information from epidemiologic studies in the HREA and PA (Frey, 2014c, p. 5), we do not agree with these commenters' conclusions regarding the usefulness of the epidemiologic studies by Strickland et al. (2010), Silverman and Ito (2010), and Mar and Koenig (2009).

More specifically, with regard to confounding by co-pollutants, we note the ISA conclusion that, in studies of O_3-associated hospital admissions and emergency department visits ''O_3 effect estimates remained relatively robust upon the inclusion of PM . . . and gaseous pollutants in two-pollutant models'' (U.S. EPA, 2013, pp. 6–152 and 6–153). This conclusion was supported by several studies that evaluated co-pollutant models including, but not limited to, two of the studies specifically highlighted by commenters (*i.e.,* Silverman and Ito, 2010; Strickland et al., 2010) (U.S. EPA, 2013, section 6.2.7.5; Figure 6–20 and Table 6–29).

Other potential uncertainties highlighted by commenters have been evaluated less frequently (*e.g.,* confounding by allergen exposure, respiratory infections). However, we note that Strickland et al. (2010) did consider the potential for pollen (a common airborne allergen) to confound the association between ambient O_3 and emergency department visits. While quantitative results were not presented, the authors reported that ''estimates for associations between ambient air pollutant concentrations and pediatric asthma emergency department visits were similar regardless of whether pollen concentrations were included in the model as covariates'' (Strickland et al., 2010, p. 309). This suggests a limited impact of aeroallergens on O_3 associations with asthma-related emergency department visits and hospital admissions.

With respect to the comment about epidemiologic studies not controlling for respiratory infections in the model, the EPA disagrees with the commenter's assertion. We recognize that asthma is a multi-etiologic disease and that air pollutants, including O_3, represent only one potential avenue to trigger an asthma exacerbation. Strickland et al. attempted to further clarify the relationship between short-term O_3 exposures and asthma emergency department visits by controlling for the possibility that respiratory infections may lead to an asthma exacerbation. By including the daily count of upper respiratory visits as a covariate in the model, Strickland et al. were able to account for the possibility that respiratory infections contribute to the daily counts of asthma emergency department visits, and to identify the O_3 effect on asthma emergency department visits. In models that controlled for upper respiratory infection visits, associations between O_3 and emergency department visits remained statistically significant (Strickland et al., Table 4 in published study), demonstrating a relatively limited influence of respiratory infections on the association observed between short-term O_3 exposures and asthma emergency department visits, contrary to the commenter's claim.

In addition, with regard to the criticism of the results reported by Mar and Koenig, the EPA disagrees with commenters who questioned the appropriateness of a zero-day lag. These commenters specifically noted uncertainty in the relative timing of the O_3 exposure and the emergency department visit when they occurred on the same day. However, based on the broader body of evidence the ISA concludes that the strongest support is for a relatively immediate respiratory response following O_3 exposures. Specifically, the ISA states that ''[t]he collective evidence indicates a rather immediate response within the first few days of O_3 exposure (*i.e.,* for lags days averaged at 0–1, 0–2, and 0–3 days) for hospital admissions and [emergency department] visits for all respiratory outcomes, asthma, and chronic obstructive pulmonary disease in all-year and seasonal analyses'' (U.S. EPA, 2013, p. 2–32). Thus, the use of a zero-day lag is consistent with the broader body of evidence supporting the occurrence of O_3-associated health effects. In addition, while Mar and Koenig reported the strongest associations for zero-day lags, they also reported positive associations for lags ranging from zero to five days (Mar and Koenig, 2009, Table 5 in the published study). In considering this study, the ISA stated that Mar and Koenig (2009) ''found consistent positive associations across individual lag days'' and that ''[f]or children, consistent positive associations were observed across all lags . . . with the strongest associations observed at lag 0 (33.1% [95% CI: 3.0, 68.5]) and lag 3 (36.8% [95% CI: 6.1, 77.2])'' (U.S. EPA, 2013, p. 6–150). Given support for a relatively immediate response to O_3 and given the generally consistent results in analyses using various lags, we disagree with commenters who asserted that the use of a zero-day lag represents an important uncertainty in the interpretation of the study by Mar and Koenig (2009).

Given all of the above, we do not agree with commenters who asserted that uncertainties in the epidemiologic evidence in general, or in specific key studies, should preclude the

[98] Air quality analyses in locations of the studies by Silverman and Ito (2010) and Strickland et al. (2010) were used in the PA to inform staff conclusions on the adequacy of the current primary O_3 standard. However, the appropriate interpretation of these analyses became less clear for standard levels below 75 ppb, as the number of days increased with monitored concentrations exceeding the level being evaluated (U.S. EPA, 2014c, Appendix 3B, Tables 3B–6 and 3B–7). Therefore, these analyses were not used in the PA to inform conclusions on potential alternative standard levels lower than 75 ppb (U.S. EPA, 2014c, Chapters 3 and 4).

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Administrator from relying on those studies to inform her decisions on the primary O_3 standard.

Some commenters also objected to the characterization in the ISA and the proposal that the results of epidemiologic studies are consistent. These commenters contended that the purported consistency of results across epidemiologic studies is the result of inappropriate selectivity on the part of the EPA in focusing on specific studies and specific results within those studies. In particular, commenters contend that EPA favors studies that show positive associations and selectively ignores certain studies that report null results. They also cite a study published after the completion of the ISA (Goodman et al., 2013) suggesting that, in papers where the results of more than one statistical model are reported, the EPA tends to report the results with the strongest associations.

The EPA disagrees that it has inappropriately focused on specific positive studies or specific positive results within individual studies. The ISA appropriately builds upon the assessment of the scientific evidence presented in previous AQCDs and ISAs.[99] When evaluating new literature, ''[s]election of studies for inclusion in the ISA is based on the general scientific quality of the study, and consideration of the extent to which the study is informative and policy-relevant'' (U.S. EPA, 2013, p. liii). In addition, ''the intent of the ISA is to provide a concise review, synthesis, and evaluation of the most policy-relevant science to serve as a scientific foundation for the review of the NAAQS, not extensive summaries of all health, ecological and welfare effects studies for a pollutant'' (U.S. EPA, 2013, p. lv). Therefore, not all studies published since the previous review would be appropriate for inclusion in the ISA.[100] With regard to the specific studies that are included in the ISA, and the analyses focused upon within given studies, the EPA notes that the ISA undergoes extensive peer review in a public setting by the CASAC. This process provides ample opportunity for CASAC and the public to comment on studies not included in the ISA, and on the specific analyses focused upon within individual studies. In endorsing the final O_3 ISA as adequate for rulemaking purposes, CASAC agreed with the selection and presentation of analyses on which to base the ISA's key conclusions.

iii. Evidence Pertaining to At-Risk Populations and Lifestages

A number of groups submitted comments on the EPA's identification of at-risk populations and lifestages. Some industry commenters who opposed revising the current standard disagreed with the EPA's identification of people with asthma or other respiratory diseases as an at-risk population for O_3-attributable effects, citing controlled human exposure studies that did not report larger O_3-induced FEV_1 decrements in people with asthma than in people without asthma. In contrast, comments from medical, environmental, and public health groups generally agreed with the at-risk populations identified by EPA, and also identified other populations that they stated should be considered at risk, including people of lower socio-economic status, people with diabetes or who are obese, pregnant women (due to reproductive and developmental effects, and African American, Asian, Hispanic/Latino or tribal communities. As support for the additional populations, these commenters cited various studies, including some that were not included in the ISA (which we have provisionally considered, as described in section I.C above).

With regard to the former group of comments stating that the evidence does not support the identification of asthmatics as an at-risk population, we disagree. As summarized in the proposal, the EPA's identification of populations at risk of O_3 effects is based on a systematic approach that assesses the current scientific evidence across the relevant scientific disciplines (*i.e.,* exposure sciences, dosimetry, controlled human exposure, toxicology, and epidemiology), with a focus on studies that conducted stratified analyses allowing for an evaluation of different populations exposed to similar O_3 concentrations within the same study design (U.S. EPA, 2013, pp. 8–1 to 8–3). Based on this established process and framework, the ISA identifies individuals with asthma among the populations and lifestages for which there is ''adequate'' evidence to support the conclusion of increased risk of O_3-related health effects. Other populations for which the evidence is adequate are individuals with certain genotypes, younger and older age groups, individuals with reduced intake of certain nutrients, and outdoor workers. These conclusions are based on consistency in findings across studies and evidence of coherence in results from different scientific disciplines.

For example, with regard to people with asthma, the ISA notes a number of epidemiologic and controlled human exposure studies reporting larger and/or more serious effects in people with asthma than in people without asthma or other respiratory diseases. These include epidemiologic studies of lung function, respiratory symptoms, and medication use, as well as controlled human exposure studies showing larger inflammatory responses and markers indicating altered immune functioning in people with asthma, and also includes evidence from animal models of asthma that informs the EPA's interpretation of the other studies. We disagree with the industry commenters' focus solely on the results of certain studies without an integrated consideration of the broader body of evidence, and wider range of respiratory endpoints. It is such an integrated approach that supports EPA's conclusion that ''there is adequate evidence for asthmatics to be an at-risk population'' (U.S. EPA, 2013, section 8.2.2).

We also disagree with commenters' misleading reference to various studies cited to support the claim that asthmatics are not at increased risk of O_3-related health effects. One of the controlled human studies cited in those comments (Mudway et al. 2001) involved asthmatic adults who were older than the healthy controls, and it is well-recognized that responses to O_3 decrease with age (U.S. EPA, 2014c, p. 3–80). Another study (Alexis et al. 2000) used subjects with mild asthma who are unlikely to be as responsive as people with more severe disease (Horstman et al., 1995) (EPA 2014c, p. 3–80). Controlled human exposure studies and epidemiologic studies of adults and children amply confirm that ''there is adequate evidence for asthmatics to be an at-risk population'' (U.S. EPA, 2014c, p. 3–81).

[99] Cf. *Coalition for Responsible Regulation* v. *EPA,* 684 F. 3d 102, 119 (D.C. Cir. 2012) (aff'd in part and rev'd in part on other grounds sub. nom *UARG* v. *EPA,* S Ct. (2014)) (''EPA simply did here what it and other decision-makers often must do to make a science-based judgment: it sought out and reviewed existing scientific evidence to determine whether a particular finding was warranted. It makes no difference that much of the scientific evidence in large part consisted of 'syntheses' of individual studies and research. Even individual studies and research papers often synthesize past work in an area and then build upon it. That is how science works'').

[100] See also section II.C.4.b below responding to comments from environmental interests that EPA inappropriately omitted many studies which (in their view) support establishing a revised standard at a level of 60 ppb or lower. Although, as explained there, the EPA disagrees with these comments, the comments illustrate that the EPA was even-handed in its consideration of the epidemiologic evidence, and most certainly did not select merely studies favorable to the point of view of revising the current standard.

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We also do not agree with the latter group of commenters that there is sufficient evidence to support the identification of additional populations as at risk of O_3-attributable health effects. Specifically with regard to pregnant women, the ISA concluded that the ''evidence is suggestive of a causal relationship between exposures to O_3 and reproductive and developmental effects'' including birth outcomes, noting that ''the collective evidence for many of the birth outcomes examined is generally inconsistent'' (U.S. EPA, 2013, pp. 7–74 and 7–75). At the time of the completion of the ISA, no studies had been identified that examined the relationship between exposure to O_3 and the health of pregnant women (*e.g.,* studies on pre-eclampsia, gestational hypertension). Due to the generally inconsistent epidemiologic evidence for effects on birth outcomes, the lack of studies on the health of pregnant women, and the lack of studies from other disciplines to provide biological plausibility for the effects examined in epidemiologic studies, pregnant women were not considered an at-risk population. Based on the EPA's provisional consideration of studies published since the completion of the ISA (I.C, above), recent studies that examine exposure to O_3 and pre-eclampsia and other health effects experienced by pregnant women are not sufficient to materially change the ISA's conclusions on at-risk populations (I.C, above). In addition, as summarized in the proposal, the ISA concluded that the evidence for other populations was either suggestive of increased risk, with further investigation needed (*e.g.,* other genetic variants, obesity, sex, and socioeconomic status), or was inadequate to determine if they were of increased risk of O_3-related health effects (influenza/infection, COPD, CVD, diabetes, hyperthyroidism, smoking, race/ethnicity, and air conditioning use) (U.S. EPA, 2013, section 2.5.4.1). The CASAC has concurred with the ISA conclusions (Frey, 2014c).

c. Comments on Exposure and Risk Assessments

This section discusses major comments on the EPA's quantitative assessments of O_3 exposures and health risks, presented in the HREA and considered in the PA, and the EPA's responses to those comments. The focus in this section is on overarching comments related to the EPA's approach to assessing exposures and risks, and to interpreting the exposure/risk results within the context of the adequacy of the current primary O_3 standard. More detailed discussion of comments and Agency responses is provided in the Response to Comments document. Section II.B.2.c.i discusses comments on estimates of O_3 exposures of concern, section II.B.2.c.ii discusses comments on estimates of the risk of O_3-induced lung function decrements, and section II.B.2.b.iii discusses comments on estimates of the risk of O_3-associated mortality and morbidity.

i. O_3 Exposures of Concern

The EPA received a number of comments expressing divergent views on the estimation of, and interpretation of, O_3 exposures of concern. In general, comments from industry, business, and some state groups opposed to revising the current primary O_3 standard asserted that the approaches and assumptions that went into the HREA assessment result in overestimates of O_3 exposures. These commenters highlighted several aspects of the assessment, asserting that the HREA overestimates the proportion of the population expected to achieve ventilation rates high enough to experience an exposure of concern; that the use of out-of-date information on activity patterns results in overestimates of the amount of time people spend being active outdoors; and that exposure estimates do not account for the fact that people spend more time indoors on days with bad air quality (*i.e.,* they engage in averting behavior). In contrast, comments from medical, public health, and environmental groups that supported revision of the current standard asserted that the HREA assessment of exposures of concern, and the EPA's interpretation of exposure estimates, understates the potential for O_3 exposures that could cause adverse health effects. These commenters claimed that the EPA's focus on 8-hour exposures understates the O_3 impacts on public health since effects in controlled human exposure studies were shown following 6.6-hour exposures; that the HREA exposure estimates do not capture the most highly exposed populations, such as highly active children and outdoor workers; and that the EPA's interpretation of estimated exposures of concern impermissibly relies on the assumption that people stay indoors to avoid dangerous air pollution (*i.e.,* that they engage in averting behavior).

In considering these comments, the EPA first notes that as discussed in the HREA, PA, and the proposal, there are aspects of the exposure assessment that, considered by themselves, can result in either overestimates or underestimates of the occurrence of O_3 exposures of concern. Commenters tended to highlight the aspects of the assessment that supported their positions, including aspects that were discussed in the HREA and/or the PA and that were considered by CASAC. In contrast, commenters tended to ignore the aspects of the assessment that did not support their positions. The EPA has carefully described and assessed the significance of the various uncertainties in the exposure analysis (U.S. EPA, 2014a, Table 5–10), noting that, in most instances, the uncertainties could result in either overestimates or underestimates of exposures and that the magnitudes of the impacts on exposure results were either ''low,'' ''low to moderate,'' or ''moderate'' (U.S. EPA, 2014a, Table 5–10).

Consistent with the characterization of uncertainties in the HREA, PA, and the proposal, the EPA agrees with some, though not all, aspects of these commenters' views. For example, the EPA agrees with the comment by groups opposed to revision that the equivalent ventilation rate (EVR) used to characterize individuals as at moderate or greater exertion in the HREA likely leads to overestimates of the number of individuals experiencing exposures of concern (U.S. EPA, 2014a, Table 5–10, p. 5–79). In addition, we note that other physiological processes that are incorporated into exposure estimates are also identified in the HREA as likely leading to overestimates of O_3 exposures, based on comparisons with the available scientific literature (U.S. EPA, 2014a, Table 5–10, p. 5–79). These aspects of the exposure assessment are estimated to have either a ''moderate'' (*i.e.,* EVR) or a ''low to moderate'' (*i.e.,* physiological processes) impact on exposure estimates (U.S. EPA, 2014a, Table 5–10, p. 5–79). Focusing on these aspects of the assessment, by themselves, could lead to the conclusion that the HREA overstates the occurrence of O_3 exposures of concern.

However, the EPA notes that there are also aspects of the HREA exposure assessment that, taken by themselves, could lead to the conclusion that the HREA understates the occurrence of O_3 exposures of concern. For example, as noted above, some medical, public health, and environmental groups asserted that the exposure assessment could underestimate O_3 exposures for highly active populations, including outdoor workers and children who spend a large portion of time outdoors during summer. In support of these assertions, commenters highlighted sensitivity analyses conducted in the HREA. However, as noted in the HREA (U.S. EPA, 2014a, Table 5–10), this

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aspect of the assessment is likely to have a ''low to moderate'' impact on exposure estimates (*i.e.,* a smaller impact than uncertainty associated with the EVR, and similar in magnitude to uncertainties related to physiological processes, as noted above). Therefore, when considered in the context of all of the uncertainties in exposure estimates, it is unlikely that the HREA's approach to using data on activity patterns leads to overall underestimates of O_3 exposures. The implications of this uncertainty are discussed in more detail below (II.C.4.b), within the context of the Administrator's decision on a revised standard level.

In addition, medical, public health, and environmental groups also pointed out that the controlled human exposures studies that provided the basis for health effect benchmarks were conducted in healthy adults, rather than at-risk populations, and these studies evaluated 6.6 hour exposures, rather than the 8-hour exposures evaluated in the HREA exposure analyses. They concluded that adverse effects would occur at lower exposure concentrations in at-risk populations, such as people with asthma, and if people were exposed for 8 hours, rather than 6.6 hours. In its review of the PA, CASAC clearly recognized these uncertainties, which provided part of the basis for CASAC's advice to consider exposures of concern for the 60 ppb benchmark. For example, when considering the results of the study by Schelegle et al. (2009) for 6.6-hour exposures to an average O_3 concentration of 72 ppb, CASAC judged that if subjects had been exposed for eight hours, the adverse combination of lung function decrements and respiratory symptoms ''could have occurred'' at lower O_3 exposure concentrations (Frey, 2014c, p. 5). With regard to at-risk populations, CASAC concluded that ''based on results for clinical studies of healthy adults, and scientific considerations of differences in responsiveness of asthmatic children compared to healthy adults, there is scientific support that 60 ppb is an appropriate exposure of concern for asthmatic children'' (Frey, 2014c, p. 8). As discussed below (II.B.3, II.C.4.b, II.C.4.c), based in large part on CASAC advice, the Administrator does consider exposure results for the 60 ppb benchmark.

Thus, rather than viewing the potential implications of various aspects of the HREA exposure assessment in isolation, as was done by many commenters, the EPA considers them together, along with other issues and uncertainties related to the interpretation of exposure estimates. As discussed above, CASAC recognized the key uncertainties in exposure estimates, as well as in the interpretation of those estimates in the HREA and PA (Frey, 2014a, c). In its review of the 2nd draft REA, CASAC concluded that ''[t]he discussion of uncertainty and variability is comprehensive, appropriately listing the major sources of uncertainty and their potential impacts on the APEX exposure estimates'' (Frey, 2014a, p. 6). Even considering these and other uncertainties, CASAC emphasized estimates of O_3 exposures of concern as part of the basis for their recommendations on the primary O_3 NAAQS. In weighing these uncertainties, which can bias exposure results in different directions but tend to have impacts that are similar in magnitude (U.S. EPA, 2014a, Table 5–10), and in light of CASAC's advice based on its review of the HREA and the PA, the EPA continues to conclude that the approach to considering estimated exposures of concern in the HREA, PA, and the proposal reflects an appropriate balance, and provides an appropriate basis for considering the public health protectiveness of the primary O_3 standard.

The EPA disagrees with other aspects of commenters' views on HREA estimates of exposures of concern. For example, commenters on both sides of the issue objected to the EPA's handling of averting behavior in exposure estimates. Some commenters who supported retaining the current standard claimed that the HREA overstates exposures of concern because available time-location-activity data do not account for averting behavior. These commenters noted sensitivity analyses in the HREA that estimated fewer exposures of concern when averting behavior was considered. In contrast, commenters supporting revision of the standard criticized the EPA's estimates of exposures of concern, claiming that the EPA ''emphasizes the role of averting behavior, noting that it may result in an overestimation of exposures of concern, and cites this behavior (essentially staying indoors or not exercising) in order to reach what it deems an acceptable level of risk'' (*e.g.,* ALA et al., p. 120).

The EPA disagrees with both of these comments. In brief, the NAAQS must ''be established at a level necessary to protect the health of persons,'' not the health of persons refraining from normal activity or resorting to medical interventions to ward off adverse effects of poor air quality (S. Rep. No. 11–1196, 91st Cong. 2d Sess. at 10). On the other hand, ignoring normal activity patterns for a pollutant like O_3, where adverse responses are critically dependent on ventilation rates, will result in a standard which provides more protection than is requisite. This issue is discussed in more detail below (II.C.4.b), within the context of the Administrator's decision on a revised standard level.

These commenters also misconstrue the EPA's limited sensitivity analyses on impacts of averting behavior in the HREA. The purpose of the HREA sensitivity analyses was to provide perspective on the potential role of averting behavior in modifying O_3 exposures. These sensitivity analyses were limited to a single urban study area, a 2-day period, and a single air quality adjustment scenario (U.S. EPA, 2014a, section 5.4.3.3). In addition, the approach used in the HREA to simulate averting behavior was itself uncertain, given the lack of actual activity pattern data that explicitly incorporated this type of behavioral response. In light of these important limitations, sensitivity analyses focused on averting behavior were discussed in the proposal within the context of the discussion of uncertainties in the HREA assessment of exposures of concern (II.C.2.b in the proposal) and, contrary to the claims of some commenters, they were not used to support the proposed decision.

Some industry groups also claimed that the time-location-activity diaries used by APEX to estimate exposures are out-of-date, and do not represent activity patterns in the current population. These commenters asserted that the use of out-of-date diary information leads to overestimates in exposures of concern. This issue was explicitly addressed in the HREA and the EPA disagrees with commenters' conclusions. In particular, diary data was updated in this review to include data from studies published as late as 2010, directly in response to CASAC concerns. In their review of this data, CASAC stated that ''[t]he addition of more recent time activity pattern data addresses a concern raised previously by the CASAC concerning how activity pattern information should be brought up to date'' (Frey, 2014a, p. 8). As indicated in the HREA (U.S. EPA, 2014a, Appendix 5G, Figures 5G–7 and Figure 5G–8), the majority of diary days used in exposure simulations of children originate from the most recently conducted activity pattern studies (U.S. EPA, 2014a, Table 5–3). In addition, evaluations included in the HREA indicated that there were not major systematic differences in time-location-activity patterns based on information from older diaries versus those collected more recently (U.S. EPA, 2014a, Appendix 5G, Figures 5G–1 and 5G–2). Given all of the above, the EPA does not agree with commenters who claimed that the time-location-activity diaries used by APEX are out-of-date, and result in overestimates of exposures of concern.

ii. Risk of O_3-Induced FEV_1 Decrements

The EPA also received a large number of comments on the FEV_1 risk assessment presented in chapter 6 of the HREA (U.S. EPA, 2014a) and summarized in the proposal (II.C.3.a in the proposal). Commenters representing medical, public health, and environmental groups generally expressed the view that these risk estimates support the need to revise the current primary O_3 standard in order to increase public health protection, though these groups also questioned some of the assumptions inherent in the EPA's interpretation of those risk estimates. For example, ALA et al. (p. 127) stated that ''[t]he HREA uses a risk function derived from a controlled human exposure study of healthy young adults to estimate lung function decrements in children, including children with asthma. This assumption could result in an underestimate of risk.'' On this same issue, commenters representing industry groups opposed to revising the standard also asserted that assumptions about children's responses to O_3 exposures are highly uncertain. In contrast to medical and public health groups, these commenters concluded that this uncertainty, along with others discussed below, call into question the use of FEV_1 risk estimates to support a decision to revise the current primary O_3 standard.

The EPA agrees that an important source of uncertainty is the approach to estimating the risk of FEV_1 decrements in children and in children with asthma based on data from healthy adults. However, this issue is discussed at length in the HREA and the PA, and was considered carefully by CASAC in its review of draft versions of these documents. The conclusions of the HREA and PA, and the advice of CASAC, were reflected in the Administrator's interpretation of FEV_1 risk estimates in the proposal, as described below. Commenters have not provided additional information that changes the EPA's views on this issue.

As discussed in the proposal (II.C.3.a.ii in the proposal), in the near absence of controlled human exposure data for children, risk estimates are based on the assumption that children exhibit the same lung function response following O_3 exposures as healthy 18-year olds (*i.e.,* the youngest age for which sufficient controlled human exposure data is available) (U.S. EPA, 2014a, section 6.5.3). As noted by CASAC (Frey, 2014a, p. 8), this assumption is justified in part by the findings of McDonnell et al. (1985), who reported that children (8–11 years old) experienced FEV_1 responses similar to those observed in adults (18–35 years old). The HREA concludes that this approach could result in either over- or underestimates of O_3-induced lung function decrements in children, depending on how children compare to the adults used in controlled human exposure studies (U.S. EPA, 2014a, section 6.5.3). With regard to people with asthma, although the evidence has been mixed (U.S. EPA, 2013, section 6.2.1.1), several studies have reported statistically larger, or a tendency for larger, O_3-induced lung function decrements in asthmatics than in non-asthmatics (Kreit et al., 1989; Horstman et al., 1995; Jorres et al., 1996; Alexis et al., 2000). On this issue, CASAC noted that ''[a]sthmatic subjects appear to be at least as sensitive, if not more sensitive, than non-asthmatic subjects in manifesting O_3-induced pulmonary function decrements'' (Frey, 2014c, p. 4). To the extent asthmatics experience larger O_3-induced lung function decrements than the healthy adults used to develop exposure-response relationships, the HREA could underestimate the impacts of O_3 exposures on lung function in asthmatics, including asthmatic children (U.S. EPA, 2014a, section 6.5.4). As noted above, these uncertainties have been considered carefully by the EPA and by CASAC during the development of the HREA and PA. In addition, the Administrator has appropriately considered these and other uncertainties in her interpretation of risk estimates, as discussed further below (II.B.3, II.C.4.b, II.C.4.c).

Some commenters additionally asserted that the HREA does not appropriately characterize the uncertainty in risk estimates for O_3-induced lung function decrements. Commenters pointed out that there is statistical uncertainty in model coefficients that is not accounted for in risk estimates. One commenter presented an analysis of this uncertainty, and concluded that there is considerable overlap between risk estimates for standard levels of 75, 70, and 65 ppb, undercutting the confidence in estimated risk reductions for standard levels below 75 ppb.

The Agency recognizes that there are important sources of uncertainty in the FEV_1 risk assessment. In some cases, these sources of uncertainty can contribute to substantial variability in risk estimates, complicating the interpretation of those estimates. For example, as discussed in the proposal, the variability in FEV_1 risk estimates across urban study areas is often greater than the differences in risk estimates between various standard levels (Table 2, above and 79 FR 75306 n. 164). Given this, and the resulting considerable overlap between the ranges of FEV_1 risk estimates for different standard levels, in the proposal the Administrator viewed these risk estimates as providing a more limited basis than exposures of concern for distinguishing between the degree of public health protection provided by alternative standard levels. Thus, although the EPA does not agree with the overall conclusions of industry commenters, their analysis of statistical uncertainty in risk estimates, and the resulting overlap between risk estimates for standard levels of 75, 70, and 65 ppb, tends to reinforce the Administrator's approach, which places greater weight on estimates of O_3 exposures of concern than on risk estimates for O_3-induced FEV_1 decrements.

iii. Risk of O_3-Associated Mortality and Morbidity

In the proposal, the Administrator placed the greatest emphasis on the results of controlled human exposure studies and on quantitative analyses based on information from these studies, and less weight on mortality and morbidity risk assessments based on information from epidemiology studies. The EPA received a number of comments on its consideration of epidemiology-based risks, with some commenters expressing support for the Agency's approach and others expressing opposition.

In general, commenters representing industry organizations or states opposed to revising the current primary O_3 standard agreed with the Administrator's approach in the proposal to viewing epidemiology-based risk estimates, though these commenters reached a different conclusion than the EPA regarding the adequacy of the current standard. In supporting their views, these commenters highlighted a number of uncertainties in the underlying epidemiologic studies, and concluded that risk estimates based on information from such studies do not provide an appropriate basis for revising the current standard. For example, commenters noted considerable spatial heterogeneity in health effect associations; the potential for co-occurring pollutants (*e.g.,* $PM_{2.5}$) to confound O_3 health effect associations;

and the lack of statistically significant O_3 health effect associations in many of the individual cities evaluated as part of multicity analyses. In contrast, some commenters representing medical, public health, or environmental organizations placed greater emphasis than the EPA on epidemiology-based risk estimates. These commenters asserted that risk estimates provide strong support for a lower standard level, and pointed to CASAC advice to support their position.

As in the proposal, the EPA continues to place the greatest weight on the results of controlled human exposure studies and on quantitative analyses based on information from these studies (particularly exposures of concern, as discussed below in II.B.3 and II.C.4), and less weight on risk analyses based on information from epidemiologic studies. In doing so, the Agency continues to note that controlled human exposure studies provide the most certain evidence indicating the occurrence of health effects in humans following specific O_3 exposures. In addition, the effects reported in these studies are due solely to O_3 exposures, and interpretation of study results is not complicated by the presence of co-occurring pollutants or pollutant mixtures (as is the case in epidemiologic studies). The Agency further notes the CASAC judgment that ''the scientific evidence supporting the finding that the current standard is inadequate to protect public health is strongest based on the controlled human exposure studies of respiratory effects'' (Frey, 2014c, p. 5). Consistent with this emphasis, the HREA conclusions reflect relatively greater confidence in the results of the exposure and risk analyses based on information from controlled human exposure studies than the results of epidemiology-based risk analyses. As discussed in the HREA (U.S. EPA, 2014a, section 9.6), several key uncertainties complicate the interpretation of these epidemiology-based risk estimates, including the heterogeneity in O_3 effect estimates between locations, the potential for exposure measurement errors in these epidemiologic studies, and uncertainty in the interpretation of the shape of concentration-response functions at lower O_3 concentrations. Commenters who opposed the EPA's approach in the proposal to viewing the results of quantitative analyses tended to highlight aspects of the evidence and CASAC advice that were considered by the EPA at the time of proposal and nothing in these commenters' views has changed those considerations. Therefore, the EPA continues to place the most emphasis on using the information from controlled human exposure studies to inform consideration of the adequacy of the primary O_3 standard.

However, while the EPA agrees that there are important uncertainties in the O_3 epidemiology-based risk estimates, the Agency disagrees with industry commenters that these uncertainties support a conclusion to retain the current standard. As discussed below, the decision to revise the current primary O_3 standard is based on the EPA's consideration of the broad body of scientific evidence, quantitative analyses of O_3 exposures and risks, CASAC advice, and public comments. While recognizing uncertainties in the epidemiology-based risk estimates here, and giving these uncertainties appropriate consideration, the Agency continues to conclude that these risk estimates contribute to the broader body of evidence and information supporting the need to revise the primary O_3 standard.

Some commenters opposed to revising the current O_3 standard highlighted the fact that, in a few urban study locations, larger risks are estimated for standard levels below 75 ppb than for the current standard with its level of 75 ppb. For example, TCEQ (p. 3) states that ''differential effects on ozone in urban areas also lead to the EPA's modeled increases in mortality in Houston and Los Angeles with decreasing ozone standards.'' These commenters cited such increases in estimated risk as part of the basis for their conclusion that the current standard should be retained.

For communities across the U.S. (including in the Houston and Los Angeles areas), exposure and risk analyses indicate that reducing emissions of O_3 precursors (NO_X, VOCs) to meet a revised standard with a level of 70 ppb will substantially reduce the occurrence of adverse respiratory effects and mortality risk attributable to high O_3 concentrations (U.S. EPA, 2014a, Appendix 9A; U.S. EPA, 2014c, sections 4.4.2.1 to 4.4.2.3). However, because of the complex chemistry governing the formation and destruction of O_3, some NO_X control strategies designed to reduce the highest ambient O_3 concentrations can also result in increases in relatively low ambient O_3 concentrations. As a result of the way the EPA's epidemiology-based risk assessments were conducted (U.S. EPA, 2014a, Chapter 7), increases estimated in low O_3 concentrations impacted mortality and morbidity risks, leading to the estimated risk increases highlighted by some commenters. However, while the EPA is confident that reducing the highest ambient O_3 concentrations will result in substantial improvements in public health, including reducing the risk of O_3-associated mortality, the Agency is far less certain about the public health implications of the changes in relatively low ambient O_3 concentrations (79 FR at 75278/3, 75291/1, and 75308/2). Therefore, reducing precursor emissions to meet a lower O_3 standard is expected to result in important reductions in O_3 concentrations from the part of the air quality distribution where the evidence provides the strongest support for adverse health effects.

Specifically, for area-wide O_3 concentrations at or above 40 ppb,[101] a revised standard with a level of 70 ppb is estimated to reduce the number of premature deaths associated with short-term O_3 concentrations by about 10%, compared to the current standard. In addition, for area-wide concentrations at or above 60 ppb, a revised standard with a level of 70 ppb is estimated to reduce O_3-associated premature deaths by about 50% to 70%.[102] The EPA views these results, which focus on the portion of the air quality distribution where the evidence indicates the most certainty regarding the occurrence of adverse O_3-attributable health effects, not only as supportive of the need to revise the current standard (II.B.3, below), but also as showing the benefits of reducing the peak O_3 concentrations associated with air quality distributions meeting the current standard (II.C.4, below).

In addition, even considering risk estimates based on the full distribution of ambient O_3 concentrations (*i.e.,* estimates influenced by decreases in higher concentrations and increases in lower concentrations), the EPA notes that, compared to the current standard, standards with lower levels are estimated to result in overall reductions in mortality risk across the urban study areas evaluated (U.S. EPA, 2014c, Figure 4–10). As discussed above (II.A.2.a, II.A.2.c), analyses in the HREA indicate that these overall risk reductions could understate the actual reductions that

[101] The ISA concludes that there is less certainty in the shape of concentration-response functions for area-wide O_3 concentrations at the lower ends of warm season distributions (*i.e.,* below about 20 to 40 ppb) (U.S. EPA, 2013, section 2.5.4.4).

[102] Available experimental studies provide the strongest evidence for O_3-induced effects following exposures to O_3 concentrations corresponding to the upper portions of typical ambient distributions. In particular, as discussed above, controlled human exposure studies showing respiratory effects following exposures to O_3 concentrations at or above 60 ppb.

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would be experienced by the U.S. population as a whole.

For example, the HREA's national air quality modeling analyses indicate that the HREA urban study areas tend to underrepresent the populations living in areas where reducing NO_X emissions would be expected to result in decreases in warm season averages of daily maximum 8-hour ambient O_3 concentrations.[103] Given the strong connection between these warm season average O_3 concentrations and risk, risk estimates for the urban study areas are likely to understate the average reductions in O_3-associated mortality and morbidity risks that would be experienced across the U.S. population as a whole upon reducing NO_X emissions (U.S. EPA, 2014a, section 8.2.3.2).

In addition, in recognizing that the reductions in modeled NO_X emissions used in the HREA's core analyses are meant to be illustrative, rather than to imply a particular control strategy for meeting a revised O_3 NAAQS, the HREA also conducted sensitivity analyses in which both NO_X and VOC emissions reductions were evaluated. In all of the urban study areas evaluated in these analyses, the increases in low O_3 concentrations were smaller for the NO_X/VOC emission reduction scenarios than the NO_X only emission reduction scenario (U.S. EPA, 2014a, Appendix 4D, section 4.7). This was most apparent for Denver, Houston, Los Angeles, New York, and Philadelphia. These results suggest that in some locations, optimized emissions reduction strategies could result in larger reductions in O_3-associated mortality and morbidity than indicated by HREA's core estimates.

Thus, the patterns of estimated mortality and morbidity risks across various air quality scenarios and locations have been evaluated and considered extensively in the HREA and the PA, as well as in the proposal. Epidemiology-based risk estimates have also been considered by CASAC, and those considerations are reflected in CASAC's advice. Specifically, in considering epidemiology-based risk estimates in its review of the REA, CASAC stated that ''[a]lthough these estimates for short-term exposure impacts are subject to uncertainty, the CASAC is confident that that the evidence of health effects of O_3 presented in the ISA and Second Draft HREA in its totality, indicates that there are meaningful reductions in mean, absolute, and relative premature mortality associated with short-term exposures to O_3 levels lower than the current standard'' (Frey, 2014a, p. 3). Commenters' views on this issue are not based on new information, but on an interpretation of the analyses presented in the HREA that is different from the EPA's, and CASAC's, interpretation. Given this, the EPA's considerations and conclusions related to this issue, as described in the proposal and as summarized briefly above, remain valid. Therefore, the EPA does not agree with commenters who cited increases in estimated risk in some locations as supporting a conclusion that the current standard should be retained.

For risk estimates of respiratory mortality associated with long-term O_3, several industry commenters supported placing more emphasis on threshold models, and including these models as part of the core analyses rather than as sensitivity analyses. The EPA agrees with these commenters that an important uncertainty in risk estimates of respiratory mortality associated with long-term O_3 stems from the potential for the existence of a threshold. Based on sensitivity analyses included in the HREA in response to CASAC advice, the existence of a threshold could substantially reduce estimated risks. CASAC discussed this issue at length during its review of the REA and supported the EPA's approach to including a range of threshold models as sensitivity analyses (Frey, 2014a p. 3). Based in part on uncertainty in the existence and identification of a threshold, the HREA concluded that lower confidence should be placed in risk estimates for respiratory mortality associated with long-term O_3 exposures (U.S. EPA, 2014a, section 9.6). This uncertainty was also a key part of the Administrator's rationale for placing only limited emphasis on risk estimates for long-term O_3 exposures. In her final decisions, discussed below (II.B.3, II.C.4.b, II.C.4.c), the Administrator continues to place only limited emphasis on these estimates. The EPA views this approach to considering risk estimates for respiratory mortality as generally consistent with the approach supported by the commenters noted above.

3. Administrator's Conclusions on the Need for Revision

This section discusses the Administrator's conclusions related to the adequacy of the public health protection provided by the current primary O_3 standard, and her final decision that the current standard is not requisite to protect public health with an adequate margin of safety. These conclusions, and her final decision, are based on the Administrator's consideration of the available scientific evidence assessed in the ISA (U.S. EPA, 2013), the exposure/risk information presented and assessed in the HREA (U.S. EPA, 2014a), the consideration of that evidence and information in the PA (U.S. EPA, 2014c), the advice of CASAC, and public comments received on the proposal.

As an initial matter, the Administrator concludes that reducing precursor emissions to achieve O_3 concentrations that meet the current primary O_3 standard will provide important improvements in public health protection, compared to recent air quality. In reaching this conclusion, she notes the discussion in section 3.4 of the PA (U.S. EPA, 2014c). In particular, the Administrator notes that this conclusion is supported by (1) the strong body of scientific evidence indicating a wide range of adverse health outcomes attributable to exposures to O_3 at concentrations commonly found in the ambient air and (2) estimates indicating decreased occurrences of O_3 exposures of concern and decreased O_3-associated health risks upon meeting the current standard, compared to recent air quality. Thus, she concludes that it would not be appropriate in this review to consider a standard that is less protective than the current standard.

After reaching the conclusion that meeting the current primary O_3 standard will provide important improvements in public health protection, and that it is not appropriate to consider a standard that is less protective than the current standard, the Administrator next considers the adequacy of the public health protection that is provided by the current standard. In doing so, the Administrator first notes that studies evaluated since the completion of the 2006 AQCD support and expand upon the strong body of evidence that, in the last review, indicated a causal relationship between short-term O_3 exposures and respiratory morbidity outcomes (U.S. EPA, 2013, section 2.5). This is the strongest causality finding possible under the ISA's hierarchical system for classifying weight of evidence for causation. In addition, the Administrator notes that the evidence for respiratory health effects attributable to long-term O_3 exposures, including the development of asthma in children, is much stronger than in previous reviews, and the ISA concludes that there is ''likely to be'' a causal relationship

[103] Specifically, the HREA urban study areas tend to underrepresent populations living in suburban, smaller urban, and rural areas, where reducing NO_X emissions would be expected to result in decreases in warm season averages of daily maximum 8-hour ambient O_3 concentrations (U.S. EPA, 2014a, section 8.2.3.2).

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between such O_3 exposures and adverse respiratory health effects (the second strongest causality finding).

Together, experimental and epidemiologic studies support conclusions regarding a continuum of O_3 respiratory effects ranging from small, reversible changes in pulmonary function, and pulmonary inflammation, to more serious effects that can result in respiratory-related emergency department visits, hospital admissions, and premature mortality. Recent animal toxicology studies support descriptions of modes of action for these respiratory effects and augment support for biological plausibility for the role of O_3 in reported effects. With regard to mode of action, evidence indicates that the initial key event is the formation of secondary oxidation products in the respiratory tract, that antioxidant capacity may modify the risk of respiratory morbidity associated with O_3 exposure, and that the inherent capacity to quench (based on individual antioxidant capacity) can be overwhelmed, especially with exposure to elevated concentrations of O_3.

In addition, based on the consistency of findings across studies and the coherence of results from different scientific disciplines, the available evidence indicates that certain populations are at increased risk of experiencing O_3-related effects, including the most severe effects. These include populations and lifestages identified in previous reviews (*i.e.,* people with asthma, children, older adults, outdoor workers) and populations identified since the last review (*i.e.,* people with certain genotypes related to antioxidant and/or anti-inflammatory status; people with reduced intake of certain antioxidant nutrients, such as Vitamins C and E).

In considering the O_3 exposure concentrations reported to elicit respiratory effects, as in the proposal, the Administrator agrees with the conclusions of the PA that controlled human exposure studies provide the most certain evidence indicating the occurrence of health effects in humans following specific O_3 exposures. In particular, she notes that the effects reported in controlled human exposure studies are due solely to O_3 exposures, and interpretation of study results is not complicated by the presence of co-occurring pollutants or pollutant mixtures (as is the case in epidemiologic studies). Therefore, consistent with CASAC advice (Frey, 2014c), she places the most weight on information from controlled human exposure studies in reaching conclusions on the adequacy of the current primary O_3 standard.

In considering the evidence from controlled human exposure studies, the Administrator first notes that these studies have reported a variety of respiratory effects in healthy adults following exposures to O_3 concentrations of 60, 63,[104] 72,[105] or 80 ppb, and higher. The largest respiratory effects, and the broadest range of effects, have been studied and reported following exposures of healthy adults to 80 ppb O_3 or higher, with most exposure studies conducted at these higher concentrations. As discussed above (II.A.1), the Administrator further notes that recent evidence includes controlled human exposure studies reporting the combination of lung function decrements and respiratory symptoms in healthy adults engaged in moderate exertion following 6.6-hour exposures to concentrations as low as 72 ppb, and lung function decrements and pulmonary inflammation following exposures to O_3 concentrations as low as 60 ppb.

As discussed in her response to public comments above (II.B.2.b.i), and in detail below (II.C.4.b, II.C.4.c), the Administrator concludes that these controlled human exposure studies indicate that adverse effects are likely to occur following exposures to O_3 concentrations below the level of the current standard. The effects observed following such exposures are coherent with the serious health outcomes that have been reported in O_3 epidemiologic studies (*e.g.,* respiratory-related hospital admissions, emergency department visits), and the Administrator judges that such effects have the potential to be important from a public health perspective.

In reaching these conclusions, she particularly notes that the combination of lung function decrements and respiratory symptoms reported to occur in healthy adults following exposures to 72 ppb O_3 meets ATS criteria for an adverse response (II.B.2.b.i, above). In specifically considering the 72 ppb exposure concentration, CASAC noted that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5). In addition, given that the controlled human exposure study reporting these results was conducted in healthy adults, CASAC judged that the adverse combination of lung function decrements and respiratory symptoms ''almost certainly occur in some people'' (*e.g.,* people with asthma) following exposures to lower O_3 concentrations (Frey, 2014c, p. 6).

While the Administrator is less certain regarding the adversity of the lung function decrements and airway inflammation that have been observed following exposures as low as 60 ppb, as discussed in more detail elsewhere in this preamble (II.B.2.b.i, II.C.4.b, II.C.4.c), she judges that these effects also have the potential to be adverse, and to be of public health importance, particularly if they are experienced repeatedly. With regard to this judgment, she specifically notes the ISA conclusion that, while the airway inflammation induced by a single exposure (or several exposures over the course of a summer) can resolve entirely, continued inflammation could potentially result in adverse effects, including the induction of a chronic inflammatory state; altered pulmonary structure and function, leading to diseases such as asthma; altered lung host defense response to inhaled microorganisms; and altered lung response to other agents such as allergens or toxins (U.S. EPA, 2013, section 6.2.3). Thus, the Administrator becomes increasingly concerned about the potential for adverse effects at 60 ppb O_3 as the number of exposures increases, though she notes that the available evidence does not indicate a particular number of occurrences of such exposures that would be required to achieve an adverse respiratory effect, and that this number is likely to vary across the population.

In addition to controlled human exposure studies, the Administrator also considers what the available epidemiologic evidence indicates with regard to the adequacy of the public health protection provided by the current primary O_3 standard. She notes that recent epidemiologic studies provide support, beyond that available in the last review, for associations between short-term O_3 exposures and a wide range of adverse respiratory outcomes (including respiratory-related hospital admissions, emergency department visits, and mortality) and with total mortality. As discussed above in the EPA responses to public comments (II.B.2.b.ii), associations with morbidity and mortality are stronger during the warm or summer months, and remain robust after adjustment for copollutants (U.S. EPA, 2013, Chapter 6).

[104] For a 60 ppb target exposure concentration, Schelegle et al. (2009) reported that the actual 6.6-hour mean exposure concentration was 63 ppb.

[105] For a 70 ppb target exposure concentration, Schelegle et al. (2009) reported that the actual 6.6-hour mean exposure concentration was 72 ppb.

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In considering information from epidemiologic studies within the context of her conclusions on the adequacy of the current standard, the Administrator specifically considers analyses in the PA that evaluate the extent to which O_3 health effect associations have been reported for air quality concentrations likely to be allowed by the current standard. She notes that such analyses can provide insight into the extent to which the current standard would allow the distributions of ambient O_3 concentrations that provided the basis for these health effect associations. While the majority of O_3 epidemiologic studies evaluated in the PA were conducted in areas that would have violated the current standard during study periods, as discussed above (II.B.2.b.ii), the Administrator observes that the study by Mar and Koenig (2009) reported associations between short-term O_3 concentrations and asthma emergency department visits in children and adults in a U.S. location that would have met the current O_3 standard over the entire study period.[106] Based on this, she notes the conclusion from the PA that the current primary O_3 standard would have allowed the distribution of ambient O_3 concentrations that provided the basis for the associations with asthma emergency department visits reported by Mar and Koenig (2009) (U.S. EPA, 2014c, section 3.1.4.2).

In addition, even in some single-city study locations where the current standard was violated (*i.e.,* those evaluated in Silverman and Ito, 2010; Strickland et al., 2010), the Administrator notes that PA analyses of reported concentration-response functions and available air quality data support the occurrence of O_3-attributable hospital admissions and emergency department visits on subsets of days with virtually all ambient O_3 concentrations below the level of the current standard. PA analyses of study area air quality further support the conclusion that exposures to the ambient O_3 concentrations present in the locations evaluated by Strickland et al. (2010) and Silverman and Ito (2010) could have plausibly resulted in the respiratory-related emergency department visits and hospital admissions reported in these studies (U.S. EPA, 2014c, section 3.1.4.2). The Administrator agrees with the PA conclusion that these analyses indicate a relatively high degree of confidence in reported statistical associations with respiratory health outcomes on days when virtually all monitored 8-hour O_3 concentrations were 75 ppb or below. She further agrees with the PA conclusion that although these analyses do not identify true design values, the presence of O_3-associated respiratory effects on such days provides insight into the types of health effects that could occur in locations with maximum ambient O_3 concentrations below the level of the current standard.

Compared to the single-city epidemiologic studies discussed above, the Administrator notes additional uncertainty in interpreting the relationships between short-term O_3 air quality in individual study cities and reported O_3 multicity effect estimates. In particular, she judges that the available multicity effect estimates in studies of short-term O_3 do not provide a basis for considering the extent to which reported O_3 health effect associations are influenced by individual locations with ambient O_3 concentrations low enough to meet the current O_3 standard, versus locations with O_3 concentrations that violate this standard.[107] While such uncertainties limit the extent to which the Administrator bases her conclusions on air quality in locations of multicity epidemiologic studies, she does note that O_3 associations with respiratory morbidity or premature mortality have been reported in several multicity studies when the majority of study locations (though not all study locations) would have met the current O_3 standard (U.S. EPA, 2014c, section 3.1.4.2).

Looking across the body of epidemiologic evidence, the Administrator thus reaches the conclusion that analyses of air quality in study locations support the occurrence of adverse O_3-associated effects at ambient O_3 concentrations that met, or are likely to have met, the current standard. She further concludes that the strongest support for this conclusion comes from single-city studies of respiratory-related hospital admissions and emergency department visits associated with short-term O_3 concentrations, with some support also from multicity studies of morbidity or mortality.

Taken together, the Administrator concludes that the scientific evidence from controlled human exposure and epidemiologic studies calls into question the adequacy of the public health protection provided by the current standard. In reaching this conclusion, she particularly notes that the current standard level is higher than the lowest O_3 exposure concentration shown to result in the adverse combination of lung function decrements and respiratory symptoms (*i.e.,* 72 ppb), and that CASAC concluded that such effects ''almost certainly occur in some people'' following exposures to O_3 concentrations below 72 ppb (Frey, 2014c, p. 6). While she also notes that the current standard level is well-above the lowest O_3 exposure concentration shown to cause respiratory effects (*i.e.,* 60 ppb), she has less confidence that the effects observed at 60 ppb are adverse (discussed in II.B.2.b.i, II.C.4.b, II.C.4.c). She further considers these effects, and the extent to which the current primary O_3 standard could protect against them, within the context of quantitative analyses of O_3 exposures (discussed below). With regard to the available epidemiologic evidence, the Administrator notes PA analyses of O_3 air quality indicating that, while most O_3 epidemiologic studies reported health effect associations with ambient O_3 concentrations that violated the current standard, a small number of single-city U.S. studies support the occurrence of asthma-related hospital admissions and emergency department visits at ambient O_3 concentrations below the level of the current standard, including one study with air quality that would have met the current standard during the study period. Some support for such O_3 associations is also provided by multicity studies of morbidity or mortality. The Administrator further judges that the biological plausibility of associations with clearly adverse morbidity effects is supported by the evidence noted above from controlled human exposure studies conducted at, or in some cases below, typical warm-season ambient O_3 concentrations.

Beyond her consideration of the scientific evidence, the Administrator also considers the results of the HREA exposure and risk analyses in reaching final conclusions regarding the adequacy of the current primary O_3 standard. In doing so, consistent with

[106] The large majority of locations evaluated in U.S. epidemiologic studies of long-term O_3 would have violated the current standard during study periods, thus providing limited insight into the adequacy of the current standard (U.S. EPA, 2014c, section 3.1.4.3).

[107] As noted in the proposal (II.E.4.d), this uncertainty applies specifically to interpreting air quality analyses within the context of multicity effect estimates for short-term O_3 concentrations, where effect estimates for individual study cities are not presented (as is the case for the key O_3 studies analyzed in the PA, with the exception of the study by Stieb et al. (2009) where none of the city-specific effect estimates for asthma emergency department visits were statistically significant). This specific uncertainty does not apply to multicity epidemiologic studies of long-term O_3 concentrations, where multicity effect estimates are based on comparisons across cities. For example, see discussion of study by Jerrett et al. (2009) in the PA (U.S. EPA, 2014c, section 3.1.4.3).

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her consideration of the evidence, she focuses primarily on quantitative analyses based on information from controlled human exposure studies (*i.e.,* exposures of concern and risk of O_3-induced FEV_1 decrements). Consistent with the considerations in the PA, and with CASAC advice (Frey, 2014c), she particularly focuses on exposure and risk estimates in children.[108] As discussed in the HREA and PA (and II.B, above), the patterns of exposure and risk estimates across urban study areas, across years, and across air quality scenarios are similar in children and adults though, because children spend more time being physically active outdoors and are more likely to experience the types of O_3 exposures shown to cause respiratory effects, larger percentages of children are estimated to experience exposures of concern and O_3-induced FEV_1 decrements. Children also have intrinsic risk factors that make them particularly susceptible to O_3-related effects (*e.g.,* higher ventilation rates relative to lung volume) (U.S. EPA, 2013, section 8.3.1.1; see section II.A.1.d above). In focusing on exposure and risk estimates in children, the Administrator recognizes that the exposure patterns for children across years, urban study areas, and air quality scenarios are indicative of the exposure patterns in a broader group of at-risk populations that also includes asthmatic adults and older adults. She judges that, to the extent the primary O_3 standard provides appropriate protection for children, it will also do so for adult populations,[109] given the larger exposures and intrinsic risk factors in children.

In first considering estimates of exposures of concern, the Administrator considers the extent to which estimates indicate that the current standard limits population exposures to the broader range of O_3 concentrations shown in controlled human exposure studies to cause respiratory effects. In doing so, she focuses on estimates of O_3 exposures of concern at or above the benchmark concentrations of 60, 70, and 80 ppb. She notes that the current O_3 standard can provide some protection against exposures of concern to a range of O_3 concentrations, including concentrations below the standard level, given that (1) with the current fourth-high form, most days will have concentrations below the standard level and that (2) exposures of concern depend on both the presence of relatively high ambient O_3 concentrations and on activity patterns in the population that result in exposures to such high concentrations while at an elevated ventilation rate (discussed in detail below, II.C.4.b and II.C.4.c).

In considering estimates of O_3 exposures of concern allowed by the current standard, she notes that while single exposures of concern could be adverse for some people, particularly for the higher benchmark concentrations (70, 80 ppb) where there is stronger evidence for the occurrence of adverse effects (II.B.2.b.i, II.C.4.b, II.C.4.c, below), she becomes increasingly concerned about the potential for adverse responses as the number of occurrences increases.[110] In particular, as discussed above with regard to inflammation, she notes that the types of lung injury shown to occur following exposures to O_3 concentrations from 60 to 80 ppb, particularly if experienced repeatedly, provide a mode of action by which O_3 may cause other more serious effects (*e.g.,* asthma exacerbations). Therefore, the Administrator places the most weight on estimates of two or more exposures of concern (*i.e.,* as a surrogate for the occurrence of repeated exposures), though she also considers estimates of one or more exposures for the 70 and 80 ppb benchmarks.

In considering estimates of exposures of concern, the Administrator first notes that if the 15 urban study areas evaluated in the HREA were to just meet the current O_3 standard, fewer than 1% of children in those areas would be estimated to experience two or more exposures of concern at or above 70 ppb, based on exposure estimates averaged over the years of analysis, though up to about 2% would be estimated to experience such exposures in the worst-case year and location (*i.e.,* year and location with the largest exposure estimates).[111] Although the Administrator is less concerned about single occurrences of exposures of concern, she notes that even single occurrences could cause adverse effects in some people, particularly for the 70 and 80 ppb benchmarks.[112] As illustrated in Table 1 (above), the current standard could allow up to about 3% of children to experience one or more exposures of concern at or above 70 ppb, averaged over the years of analysis, and up to about 8% in the worst-case year and location. In addition, in the worst-case year and location, the current standard could allow about 1% of children to experience at least one exposure of concern at or above 80 ppb, the highest benchmark evaluated.

While the Administrator has less confidence in the adversity of the effects observed following exposures to 60 ppb O_3 (II.B.2.b.i, II.C.4.b, II.C.4.c), particularly for single exposures, she judges that the potential for adverse effects increases as the number of exposures of concern increases. With regard to the 60 ppb benchmark, she particularly notes that the current standard is estimated to allow approximately 3 to 8% of children in urban study areas, including approximately 3 to 8% of asthmatic children, to experience two or more exposures of concern to O_3 concentrations at or above 60 ppb, based on estimates averaged over the years of analysis. To provide some perspective on the average percentages estimated, the Administrator notes that they correspond to almost 900,000 children in urban study areas, including about 90,000 asthmatic children. Nationally, if the current standard were to be just met, the number of children experiencing such exposures would be larger.

Based on her consideration of these estimates within the context of her judgments on adversity, as discussed in her responses to public comments (II.B.2.b.i, II.C.4.b), the Administrator concludes that the exposures projected to remain upon meeting the current standard can reasonably be judged to be important from a public health perspective. In particular, given that the average percent of children estimated to experience two or more exposures of concern for the 60 ppb benchmark approaches 10% in some areas, even based on estimates averaged over the

[108] She focuses on estimates for all children and estimates for children with asthma, noting that exposure and risk estimates for these groups are virtually indistinguishable in terms of the percent estimated to experience exposures of concern or O_3-induced FEV_1 decrements (U.S. EPA, 2014c, sections 3.2 and 4.4.2).

[109] As noted below (II.C.4.2), this includes populations of highly active adults, such as outdoor workers. Limited sensitivity analyses in the HREA indicate that when diaries were selected to mimic exposures that could be experienced by outdoor workers, the percentages of modeled individuals estimated to experience exposures of concern were generally similar to the percentages estimated for children (*i.e.,* using the full database of diary profiles) in the urban study areas and years with the largest exposure estimates (U.S. EPA, 2014, section 5.4.3.2, Figure 5–14).

[110] Not all people who experience an exposure of concern will experience an adverse effect (even members of at-risk populations). For the endpoints evaluated in controlled human exposure studies, the number of those experiencing exposures of concern who will experience adverse effects cannot be reliably quantified.

[111] Virtually no children in those areas would be estimated to experience two or more exposures of concern at or above 80 ppb.

[112] That is, adverse effects are a possible outcome of single exposures of concern at/above 70 or 80 ppb, though the available information is not sufficient to estimate the likelihood of such effects.

years of the analysis, she concludes that the current standard does not incorporate an adequate margin of safety against the potentially adverse effects that can occur following repeated exposures at or above 60 ppb. Although she has less confidence that the effects observed at 60 ppb are adverse, compared to the effects at and above 72 ppb, she judges that this approach to considering the results for the 60 ppb benchmark is appropriate given CASAC advice, which clearly focuses the EPA on considering the effects observed at 60 ppb (Frey, 2014c) (II.C.4.b, II.C.4.c below).[113] This approach to considering estimated exposures of concern is consistent with setting standards that provide some safeguard against dangers to human health that are not fully certain (*i.e.,* standards that incorporate an adequate margin of safety) (See, *e.g., State of Mississippi,* 744 F. 3d at 1353).

In addition to estimated exposures of concern, the Administrator also considers HREA estimates of the risk of O_3-induced FEV_1 decrements ≥10 and 15%. In doing so, she particularly notes CASAC advice that ''estimation of FEV_1 decrements of ≥15% is appropriate as a scientifically relevant surrogate for adverse health outcomes in active healthy adults, whereas an FEV_1 decrement of ≥10% is a scientifically relevant surrogate for adverse health outcomes for people with asthma and lung disease'' (Frey, 2014c, p. 3). The Administrator notes that while single occurrences of O_3-induced lung function decrements could be adverse for some people, as discussed above (II.B.1), she agrees with the judgment in past reviews that a more general consensus view of the potential adversity of such decrements emerges as the frequency of occurrences increases. Therefore, as in the proposal, the Administrator focuses primarily on the estimates of two or more O_3-induced lung function decrements. When averaged over the years evaluated in the HREA, the Administrator notes that the current standard is estimated to allow about 1 to 3% of children in the 15 urban study areas (corresponding to almost 400,000 children) to experience two or more O_3-induced lung function decrements ≥15%, and to allow about 8 to 12% of children (corresponding to about 180,000 asthmatic children) to experience two or more O_3-induced lung function decrements ≥10%.

In further considering the HREA results, the Administrator considers the epidemiology-based risk estimates. As discussed in the proposal, compared to the weight given to HREA estimates of exposures of concern and lung function risks, she places relatively less weight on epidemiology-based risk estimates. In giving some consideration to these risk estimates, as discussed in the proposal and above in the EPA's responses to public comments (II.B.2.b.iii), the Administrator focuses on the risks associated with O_3 concentrations in the upper portions of ambient distributions. In doing so, she notes the increasing uncertainty associated with the shapes of concentration-response curves for O_3 concentrations in the lower portions of ambient distributions and the evidence from controlled human exposure studies, which provide the strongest support for O_3-induced effects following exposures to O_3 concentrations corresponding to the upper portions of typical ambient distributions (*i.e.,* 60 ppb and above). Even when considering only area-wide O_3 concentrations from the upper portions of seasonal distributions (*i.e.,* ≥40, 60 ppb, Table 3 in the proposal), the Administrator notes that the general magnitude of mortality risk estimates suggests the potential for a substantial number of O_3-associated deaths and adverse respiratory events to occur nationally, even when the current standard is met (79 FR 75277 and II.B.2.c.iii above).

In addition to the evidence and exposure/risk information discussed above, the Administrator also takes note of the CASAC advice in the current review, in the 2008 review and decision establishing the current standard, and in the 2010 reconsideration of the 2008 decision. As discussed in more detail above, the current CASAC ''finds that the current NAAQS for ozone is not protective of human health'' and ''unanimously recommends that the Administrator revise the current primary ozone standard to protect public health'' (Frey, 2014c, p. 5). The prior CASAC O_3 Panel likewise recommended revision of the current standard to one with a lower level due to the lack of protectiveness of the current standard. This earlier recommendation was based entirely on the evidence and information in the record for the 2008 standard decision, which, as discussed above, has been substantially strengthened in the current review (Samet, 2011; Frey and Samet, 2012).

In consideration of all of the above, the Administrator concludes that the current primary O_3 standard is not requisite to protect public health with an adequate margin of safety, and that it should be revised to provide increased public health protection. This decision is based on the Administrator's conclusions that the available evidence and exposure and risk information clearly call into question the adequacy of public health protection provided by the current primary standard such that it is not appropriate, within the meaning of section 109(d)(1) of the CAA, to retain the current standard. With regard to the evidence, she particularly notes that the current standard level is higher than the lowest O_3 exposure concentration shown to result in the adverse combination of lung function decrements and respiratory symptoms (*i.e.,* 72 ppb), and also notes CASAC's advice that at-risk groups (*e.g.,* people with asthma) could experience adverse effects following exposure to lower concentrations. In addition, while the Administrator is less certain about the adversity of the effects that occur following lower exposure concentrations, she judges that recent controlled human exposure studies at 60 ppb provide support for a level below 75 ppb in order to provide an increased margin of safety, compared to the current standard, against effects with the potential to be adverse, particularly if they are experienced repeatedly. With regard to O_3 epidemiologic studies, she notes that while most available studies reported health effect associations with ambient O_3 concentrations that violated the current standard, a small number provide support for the occurrence of adverse respiratory effects at ambient O_3 concentrations below the level of the current standard.[114]

Based on the analyses in the HREA, the Administrator concludes that the exposures and risks projected to remain upon meeting the current standard can reasonably be judged to be important from a public health perspective. In particular, this conclusion is based on her judgment that it is appropriate to set a standard that would be expected to eliminate, or almost eliminate, exposures of concern at or above 70 and 80 ppb. In addition, given that the average percent of children estimated to experience two or more exposures of concern for the 60 ppb benchmark approaches 10% in some urban study areas, the Administrator concludes that the current standard does not incorporate an adequate margin of safety

[113] Though this advice is less clear regarding the adversity of effects at 60 ppb than CASAC's advice regarding the adversity of effects at 72 ppb (II.C.4.b, II.C.4.c).

[114] Courts have repeatedly held that this type of evidence justifies an Administrator's conclusion that it is ''appropriate'' (within the meaning of section 109 (d)(1) of the CAA) to revise a primary NAAQS to provide further protection of public health. See *e.g. Mississippi,* 744 F. 3d at 1345; *American Farm Bureau,* 559 F. 3d at 525–26.

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against the potentially adverse effects that could occur following repeated exposures at or above 60 ppb. Beyond estimated exposures of concern, the Administrator concludes that the HREA risk estimates (FEV_1 risk estimates, mortality risk estimates) further support a conclusion that the O_3-associated health effects estimated to remain upon just meeting the current standard are an issue of public health importance on a broad national scale. Thus, she concludes that O_3 exposure and risk estimates, when taken together, support a conclusion that the exposures and health risks associated with just meeting the current standard can reasonably be judged important from a public health perspective, such that the current standard is not sufficiently protective and does not incorporate an adequate margin of safety.

In the next section, the Administrator considers what revisions are appropriate in order to set a standard that is requisite to protect public health with an adequate margin of safety.

C. Conclusions on the Elements of a Revised Primary Standard

Having reached the conclusion that the current O_3 standard is not requisite to protect public health with an adequate margin of safety, based on the currently available scientific evidence and exposure/risk information, the Administrator next considers the range of alternative standards supported by that evidence and information. Consistent with her consideration of the adequacy of the current standard, the Administrator's conclusions on the elements of the primary standard are informed by the available scientific evidence assessed in the ISA, exposure/risk information presented and assessed in the HREA, the evidence-based and exposure-/risk-based considerations and conclusions in the PA, CASAC advice, and public comments. The sections below discuss the evidence and exposure/risk information, CASAC advice and public input, and the Administrator's proposed conclusions, for the major elements of the NAAQS: Indicator (II.C.1), averaging time (II.C.2), form (II.C.3), and level (II.C.4).

1. Indicator

In the 2008 review, the EPA focused on O_3 as the most appropriate indicator for a standard meant to provide protection against ambient photochemical oxidants. In this review, while the complex atmospheric chemistry in which O_3 plays a key role has been highlighted, no alternatives to O_3 have been advanced as being a more appropriate indicator for ambient photochemical oxidants. More specifically, the ISA noted that O_3 is the only photochemical oxidant (other than NO_2) that is routinely monitored and for which a comprehensive database exists (U.S. EPA, 2013, section 3.6). Data for other photochemical oxidants (*e.g.,* peroxyacetyl nitrate, hydrogen peroxide, etc.) typically have been obtained only as part of special field studies. Consequently, no data on nationwide patterns of occurrence are available for these other oxidants; nor are extensive data available on the relationships of concentrations and patterns of these oxidants to those of O_3 (U.S. EPA, 2013, section 3.6). In its review of the second draft PA, CASAC stated ''The indicator of ozone is appropriate based on its causal or likely causal associations with multiple adverse health outcomes and its representation of a class of pollutants known as photochemical oxidants'' (Frey, 2014c, p. ii).

In addition, the PA notes that meeting an O_3 standard can be expected to provide some degree of protection against potential health effects that may be independently associated with other photochemical oxidants, even though such effects are not discernible from currently available studies indexed by O_3 alone (U.S. EPA, 2014c, section 4.1). That is, since the precursor emissions that lead to the formation of O_3 generally also lead to the formation of other photochemical oxidants, measures leading to reductions in population exposures to O_3 can generally be expected to lead to reductions in population exposures to other photochemical oxidants. In considering this information, and CASAC's advice, the Administrator reached the proposed conclusion that O_3 remains the most appropriate indicator for a standard meant to provide protection against photochemical oxidants.[115]

The EPA received very few comments on the indicator of the primary standard. Those who did comment supported the proposed decision to retain O_3 as the indicator, noting the rationale put forward in the preamble to the proposed rule. These commenters generally expressed support for retaining the current indicator in conjunction with retaining other elements of the current standard, such as the averaging time and form. After considering the available evidence, CASAC advice, and public comments, the Administrator concludes that O_3 remains the most appropriate indicator for a standard meant to provide protection against photochemical oxidants. Therefore, she is retaining O_3 as the indicator for the primary standard in this final rule.

2. Averaging Time

The EPA established the current 8-hour averaging time [116] for the primary O_3 NAAQS in 1997 (62 FR 38856). The decision on averaging time in that review was based on numerous controlled human exposure and epidemiologic studies reporting associations between adverse respiratory effects and 6- to 8-hour O_3 concentrations (62 FR 38861). The EPA also noted that a standard with a maximum 8-hour averaging time is likely to provide substantial protection against respiratory effects associated with 1-hour peak O_3 concentrations. The EPA reached similar conclusions in the last O_3 NAAQS review and thus, the EPA retained the 8-hour averaging time in 2008.

In reaching a proposed conclusion on averaging time in the current review, the Administrator considered the extent to which the available evidence continues to support the appropriateness of a standard with an 8-hour averaging time (79 FR 75292). Specifically, the Administrator considered the extent to which the available information indicates that a standard with the current 8-hour averaging time provides appropriate protection against short- and long-term O_3 exposures. These considerations from the proposal are summarized below in sections II.C.2.a (short-term) and II.C.2.b (long-term). Section II.C.2.c summarizes the Administrator's proposed decision on averaging time. Section II.C.2.d discusses comments received on averaging time. Section II.C.2.e presents the Administrator's final decision regarding averaging time.

a. Short-Term

As an initial consideration with respect to the most appropriate averaging time for the O_3 NAAQS, in the proposal the Administrator noted that the strongest evidence for O_3-associated health effects is for respiratory effects following short-term exposures. More specifically, the Administrator noted the ISA conclusion that the evidence is ''sufficient to infer a causal relationship'' between short-term O_3 exposures and respiratory effects. The ISA also judges that for short-term O_3 exposures, the evidence indicates ''likely to be causal'' relationships with

[115] The DC Circuit upheld the use of O_3 as the indicator for photochemical oxidants based on these same considerations. *American Petroleum Inst.* v. *Costle,* 665 F. 2d 1176, 1186 (D.C. Cir. 1981).

[116] This 8-hour averaging time reflects daily maximum 8-hour average O_3 concentrations.

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both cardiovascular effects and mortality (U.S. EPA, 2013, section 2.5.2). Therefore, as in past reviews, the Administrator noted that the strength of the available scientific evidence provides strong support for a standard that protects the public health against short-term exposures to O_3.

In first considering the level of support available for specific short-term averaging times, the Administrator noted in the proposal the evidence available from controlled human exposure studies. As discussed in more detail in Chapter 3 of the PA, substantial health effects evidence from controlled human exposure studies demonstrates that a wide range of respiratory effects (*e.g.,* pulmonary function decrements, increases in respiratory symptoms, lung inflammation, lung permeability, decreased lung host defense, and airway hyperresponsiveness) occur in healthy adults following 6.6-hour exposures to O_3 (U.S. EPA, 2013, section 6.2.1.1). Compared to studies evaluating shorter exposure durations (*e.g.,* 1-hour), studies evaluating 6.6-hour exposures in healthy adults have reported respiratory effects at lower O_3 exposure concentrations and at more moderate levels of exertion.

The Administrator also noted in the proposal the strength of evidence from epidemiologic studies that evaluated a wide variety of populations (*e.g.,* including at-risk lifestages and populations, such as children and people with asthma, respectively). A number of different averaging times have been used in O_3 epidemiologic studies, with the most common being the max 1-hour concentration within a 24-hour period (1-hour max), the max 8-hour average concentration within a 24-hour period (8-hour max), and the 24-hour average. These studies are assessed in detail in Chapter 6 of the ISA (U.S. EPA, 2013). Limited evidence from time-series and panel epidemiologic studies comparing risk estimates across averaging times does not indicate that one exposure metric is more consistently or strongly associated with respiratory health effects or mortality, though the ISA notes some evidence for ''smaller O_3 risk estimates when using a 24-hour average exposure metric'' (U.S. EPA, 2013, section 2.5.4.2; p. 2–31). For single- and multi-day average O_3 concentrations, lung function decrements were associated with 1-hour max, 8-hour max, and 24-hour average ambient O_3 concentrations, with no strong difference in the consistency or magnitude of association among the averaging times (U.S. EPA, 2013, p. 6–71). Similarly, in studies of short-term exposure to O_3 and mortality, Smith et al. (2009) and Darrow *et al.* (2011) have reported high correlations between risk estimates calculated using 24-hour average, 8-hour max, and 1-hour max averaging times (U.S. EPA, 2013, p. 6–253). Thus, the Administrator noted that the epidemiologic evidence alone does not provide a strong basis for distinguishing between the appropriateness of 1-hour, 8-hour, and 24-hour averaging times.

Considering the health information discussed above, in the proposal the Administrator concluded that an 8-hour averaging time remains appropriate for addressing health effects associated with short-term exposures to ambient O_3. An 8-hour averaging time is similar to the exposure periods evaluated in controlled human exposure studies, including recent studies that provide evidence for respiratory effects following exposures to O_3 concentrations below the level of the current standard. In addition, epidemiologic studies provide evidence for health effect associations with 8-hour O_3 concentrations, as well as with 1-hour and 24-hour concentrations. As in previous reviews, the Administrator noted that a standard with an 8-hour averaging time (combined with an appropriate standard form and level) would also be expected to provide substantial protection against health effects attributable to 1-hour and 24-hour exposures (*e.g.,* 62 FR 38861, July 18, 1997). This conclusion is consistent with the advice received from CASAC that ''the current 8-hour averaging time is justified by the combined evidence from epidemiologic and clinical studies'' (Frey, 2014c, p. 6).

b. Long-Term

The ISA concludes that the evidence for long-term O_3 exposures indicates that there is ''likely to be a causal relationship'' with respiratory effects (U.S. EPA, 2013, chapter 7). Thus, in this review the Administrator also considers the extent to which currently available evidence and exposure/risk information suggests that a standard with an 8-hour averaging time can provide protection against respiratory effects associated with longer term exposures to ambient O_3.

In considering this issue in the 2008 review of the O_3 NAAQS, the Staff Paper noted that ''because long-term air quality patterns would be improved in areas coming into attainment with an 8-hr standard, the potential risk of health effects associated with long-term exposures would be reduced in any area meeting an 8-hr standard'' (U.S. EPA, 2007, p. 6–57). In the current review, the PA further evaluates this issue, with a focus on the long-term O_3 metrics reported to be associated with mortality or morbidity in recent epidemiologic studies. As discussed in section 3.1.3 of the PA (U.S. EPA, 2014c, section 4.2), much of the recent evidence for such associations is based on studies that defined long-term O_3 in terms of seasonal averages of daily maximum 1-hour or 8-hour concentrations.

As an initial consideration, in the proposal the Administrator noted the risk results from the HREA for respiratory mortality associated with long-term O_3 concentrations. These HREA analyses indicate that as air quality is adjusted to just meet the current 8-hour standard, most urban study areas are estimated to experience reductions in respiratory mortality associated with long-term O_3 concentrations based on the seasonal averages of 1-hour daily maximum O_3 concentrations evaluated in the study by Jerrett et al. (2009) (U.S. EPA, 2014a, chapter 7).[117] As air quality is adjusted to meet lower alternative standard levels, for standards based on 3-year averages of the annual fourth-highest daily maximum 8-hour O_3 concentrations, respiratory mortality risks are estimated to be reduced further in urban study areas. This analysis indicates that an O_3 standard with an 8-hour averaging time, when coupled with an appropriate form and level, can reduce respiratory mortality reported to be associated with long-term O_3 concentrations.

In further considering the study by Jerrett et al. (2009), in the proposal the Administrator noted the PA comparison of long-term O_3 concentrations following model adjustment in urban study areas (*i.e.,* adjusted to meet the current and alternative 8-hour standards) to the concentrations present in study cities that provided the basis for the positive and statistically significant association with respiratory mortality. As indicated in Table 4–3 of the PA (U.S. EPA, 2014c, section 4.2), this comparison suggests that a standard with an 8-hour averaging time can decrease seasonal averages of 1-hour daily maximum O_3 concentrations, and can maintain those O_3 concentrations below the seasonal average concentration where the study indicates the most confidence in the reported concentration-response relationship with respiratory mortality (U.S. EPA, 2014c, sections 4.2 and 4.4.1).

[117] Though the Administrator also notes important uncertainties associated with these risk estimates, as discussed in section II.C.3.b of the proposal.

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The Administrator also noted in the proposal that the HREA conducted analyses evaluating the impacts of reducing regional NO_X emissions on the seasonal averages of daily maximum 8-hour O_3 concentrations. Seasonal averages of 8-hour daily max O_3 concentrations reflect long-term metrics that have been reported to be associated with respiratory morbidity effects in several recent O_3 epidemiologic studies (*e.g.,* Islam *et al.*, 2008; Lin *et al.*, 2008a, 2008b; Salam et al., 2009). The HREA analyses indicate that the large majority of the U.S. population lives in locations where reducing NO_X emissions would be expected to result in decreases in seasonal averages of daily max 8-hour ambient O_3 concentrations (U.S. EPA, 2014a, chapter 8). Thus, consistent with the respiratory mortality risk estimates noted above, these analyses suggest that reductions in O_3 precursor emissions in order to meet a standard with an 8-hour averaging time would also be expected to reduce the long-term O_3 concentrations that have been reported in recent epidemiologic studies to be associated with respiratory morbidity.

c. Administrator's Proposed Conclusion on Averaging Time

In the proposal the Administrator noted that, when taken together, the analyses summarized above indicate that a standard with an 8-hour averaging time, coupled with the current fourth-high form and an appropriate level, would be expected to provide appropriate protection against the short- and long-term O_3 concentrations that have been reported to be associated with respiratory morbidity and mortality. The CASAC agreed with this conclusion, stating that ''[t]he current 8-hour averaging time is justified by the combined evidence from epidemiologic and clinical studies'' and that ''[t]he 8-hour averaging window also provides protection against the adverse impacts of long-term ozone exposures, which were found to be ''likely causal'' for respiratory effects and premature mortality'' (Frey, 2014c, p. 6). Therefore, considering the available evidence and exposure risk information, and CASAC's advice, the Administrator proposed to retain the current 8-hour averaging time, and not to set an additional standard with a different averaging time.

d. Comments on Averaging Time

Most public commenters did not address the issue of whether the EPA should consider additional or alternative averaging times. Of those who did address this issue, some commenters representing state agencies or industry groups agreed with the proposed decision to retain the current 8-hour averaging time, generally noting the supportive evidence discussed in the preamble to the proposed rule. In contrast, several medical organizations and environmental groups questioned the degree of health protection provided by a standard based on an 8-hour averaging time. For example, one group asserted that ''[a]veraging over any time period, such as 8 hours, is capable of hiding peaks that may be very substantial if they are brief enough.''

The EPA agrees with these commenters that an important issue in the current review is the appropriateness of using a standard with an 8-hour averaging time to protect against adverse health effects that are attributable to a wide range of O_3 exposure durations, including those shorter and longer than 8 hours. This is an issue that has been thoroughly evaluated by the EPA in past reviews, as well as in the current review.

The 8-hour O_3 NAAQS was originally set in 1997, as part of revising the then-existing standard with its 1-hour averaging time, and was retained in the review completed in 2008 (73 FR 16472). In both of these reviews, several lines of evidence and information provided support for an 8-hour averaging time rather than a shorter averaging time. For example, substantial health evidence demonstrated associations between a wide range of respiratory effects and 6- to 8-hour exposures to relatively low O_3 concentrations (*i.e.,* below the level of the 1-hour O_3 NAAQS in place prior to the review completed in 1997). A standard with an 8-hour averaging time was determined to be more directly associated with health effects of concern at lower O_3 concentrations than a standard with a 1-hour averaging time. In addition, results of quantitative analyses showed that a standard with an 8-hour averaging time can effectively limit both 1- and 8-hour exposures of concern, and that an 8-hour averaging time results in a more uniformly protective national standard than a 1-hour averaging time. In past reviews, CASAC has agreed that an 8-hour averaging time is appropriate.

In reaching her proposed decision to retain the 8-hour averaging time in the current review, the Administrator again considered the body of evidence for adverse effects attributable to a wide range of O_3 exposure durations, including studies specifically referenced by public commenters who questioned the protectiveness of a standard with an 8-hour averaging time. For example, as noted above a substantial body of health effects evidence from controlled human exposure studies demonstrates that a wide range of respiratory effects occur in healthy adults following 6.6-hour exposures to O_3 (U.S. EPA, 2013, section 6.2.1.1). Compared to studies evaluating shorter exposure durations (*e.g.,* 1-hour), studies evaluating 6.6-hour exposures in healthy adults have reported respiratory effects at lower O_3 exposure concentrations and at more moderate levels of exertion. The Administrator also noted the strength of evidence from epidemiologic studies that evaluated a number of different averaging times, with the most common being the maximum 1-hour concentration within a 24-hour period (1-hour max), the maximum 8-hour average concentration within a 24-hour period (8-hour max), and the 24-hour average. Evidence from time-series and panel epidemiologic studies comparing risk estimates across averaging times does not indicate that one exposure metric is more consistently or strongly associated with respiratory health effects or mortality (U.S. EPA, 2013, section 2.5.4.2; p. 2–31). For single- and multi-day average O_3 concentrations, lung function decrements were associated with 1-hour max, 8-hour max, and 24-hour average ambient O_3 concentrations, with no strong difference in the consistency or magnitude of association among the averaging times (U.S. EPA, 2013, p. 6–71). Similarly, in studies of short-term exposure to O_3 and mortality, Smith *et al.* (2009) and Darrow et al. (2011) have reported high correlations between risk estimates calculated using 24-hour average, 8-hour max, and 1-hour max averaging times (U.S. EPA, 2013, p. 6–253). Thus, the epidemiologic evidence does not provide a strong basis for distinguishing between the appropriateness of 1-hour, 8-hour, and 24-hour averaging times.

In addition, quantitative exposure and risk analyses in the HREA are based on an air quality adjustment approach that estimates hourly O_3 concentrations, and on scientific studies that evaluated health effects attributable to a wide range of O_3 exposure durations. For example, the risk of lung function decrements is estimated using a model based on controlled human exposure studies with exposure durations ranging from 2 to 7.6 hours (U.S. EPA, 2013, section 6.2.1.1). Epidemiology-based risk estimates are based on studies that reported health effect associations with short-term ambient O_3 concentrations ranging from 1-hour to 24-hours and with long-term seasonal average concentrations (U.S. EPA, 2014a, Table 7–2). Thus, the HREA estimated health

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risks associated with a wide range of O_3 exposure durations and the Administrator's conclusions on averaging time in the current review are based, in part, on consideration of these estimates.

When taken together, the evidence and analyses indicate that a standard with an 8-hour averaging time, coupled with the current fourth-high form and an appropriate level, would be expected to provide appropriate protection against the short- and long-term O_3 concentrations that have been reported to be associated with respiratory morbidity and mortality. The CASAC agreed with this, stating the following (Frey, 2014c, p. 6):

> The current 8-hour averaging time is justified by the combined evidence from epidemiologic and clinical studies referenced in Chapter 4. Results from clinical studies, for example, show a wide range of respiratory effects in healthy adults following 6.6 hours of exposure to ozone, including pulmonary function decrements, increases in respiratory symptoms, lung inflammation, lung permeability, decreased lung host defense, and airway hyperresponsiveness. These findings are supported by evidence from epidemiological studies that show causal associations between short-term exposures of 1, 8 and 24-hours and respiratory effects and ''likely to be causal'' associations for cardiovascular effects and premature mortality. The 8-hour averaging window also provides protection against the adverse impacts of long-term ozone exposures, which were found to be ''likely causal'' for respiratory effects and premature mortality.

Given all of the above, the EPA disagrees with commenters who question the protectiveness of an O_3 standard with an 8-hour averaging time, particularly for an 8-hour standard with the revised level of 70 ppb that is being established in this review, as discussed below (II.C.4).

e. Administrator's Final Decision Regarding Averaging Time

In considering the evidence and information summarized in the proposal and discussed in detail in the ISA, HREA, and PA; CASAC's views; and public comments, the Administrator concludes that a standard with an 8-hour averaging time can effectively limit health effects attributable to both short- and long-term O_3 exposures. As was the case in the proposal, this final conclusion is based on (1) the strong evidence that continues to support the importance of protecting public health against short-term O_3 exposures (*e.g.,* ≤ 1-hour to 24-hour) and (2) analyses in the HREA and PA supporting the conclusion that the current 8-hour averaging time can effectively limit long-term O_3 exposures. Furthermore, the Administrator observes that the CASAC Panel agreed with the choice of averaging time (Frey, 2014c). Therefore, in the current review, the Administrator concludes that it is appropriate to retain the 8-hour averaging time and to not set a separate standard with a different averaging time in this final rule.

3. Form

The ''form'' of a standard defines the air quality statistic that is to be compared to the level of the standard in determining whether an area attains that standard. The foremost consideration in selecting a form is the adequacy of the public health protection provided by the combination of the form and the other elements of the standard. In this review, the Administrator considers the extent to which the available evidence and/or information continue to support the appropriateness of a standard with the current form, defined by the 3-year average of annual fourth-highest 8-hour daily maximum O_3 concentrations. Section II.C.3.a below summarizes the basis for the current form. Section II.C.3.b discusses the Administrator's proposed decision to retain the current form. Section II.C.3.c discusses public comments received on the form of the primary standard. Section II.C.3.d discusses the Administrator's final decision on form.

a. Basis for the Current Form

The EPA established the current form of the primary O_3 NAAQS in 1997 (62 FR 38856). Prior to that time, the standard had a ''1-expected-exceedance'' form.[118] An advantage of the current concentration-based form recognized in the 1997 review is that such a form better reflects the continuum of health effects associated with increasing ambient O_3 concentrations. Unlike an expected exceedance form, a concentration-based form gives proportionally more weight to years when 8-hour O_3 concentrations are well above the level of the standard than years when 8-hour O_3 concentrations are just above the level of the standard.[119] The EPA judged it appropriate to give more weight to higher O_3 concentrations, given that available health evidence indicated a continuum of effects associated with exposures to varying concentrations of O_3, and given that the extent to which public health is affected by exposure to ambient O_3 is related to the actual magnitude of the O_3 concentration, not just whether the concentration is above a specified level.

During the 1997 review, the EPA considered a range of alternative ''concentration-based'' forms, including the second-, third-, fourth- and fifth-highest daily maximum 8-hour concentrations in an O_3 season. The fourth-highest daily maximum was selected, recognizing that a less restrictive form (*e.g.,* fifth-highest) would allow a larger percentage of sites to experience O_3 peaks above the level of the standard, and would allow more days on which the level of the standard may be exceeded when the site attains the standard (62 FR 38856). The EPA also considered setting a standard with a form that would provide a margin of safety against possible but uncertain chronic effects, and would provide greater stability to ongoing control programs.[120] A more restrictive form was not selected, recognizing that the differences in the degree of protection afforded by the alternatives were not well enough understood to use any such differences as a basis for choosing the most restrictive forms (62 FR 38856).

In the 2008 review, the EPA additionally considered the potential value of a percentile-based form. In doing so, the EPA recognized that such a statistic is useful for comparing datasets of varying length because it samples approximately the same place in the distribution of air quality values, whether the dataset is several months or several years long. However, the EPA concluded that a percentile-based statistic would not be effective in ensuring the same degree of public health protection across the country. Specifically, a percentile-based form would allow more days with higher air quality values in locations with longer O_3 seasons relative to locations with shorter O_3 seasons. Thus, in the 2008 review, the EPA concluded that a form based on the nth-highest maximum O_3 concentration would more effectively ensure that people who live in areas

[118] For a standard with a 1-expected-exceedance form to be met at an air quality monitoring site, the fourth-highest air quality value in 3 years, given adjustments for missing data, must be less than or equal to the level of the standard.

[119] As discussed (61 FR 65731), this is because with an exceedance-based form, days on which the ambient O_3 concentration is well above the level of the standard are given equal weight to those days on which the O_3 concentration is just above the standard (*i.e.,* each day is counted as one exceedance), even though the public health impact of such days would be very different. With a concentration-based form, days on which higher O_3 concentrations occur would weigh proportionally more than days with lower O_3 concentrations since the actual concentrations are used directly to calculate whether the standard is met or violated.

[120] See *American Trucking Assn's* v. *EPA,* 283 F. 3d at 374–75 (less stable implementation programs may be less effective and would thereby provide less public health protection; EPA may therefore legitimately consider programmatic stability in determining the form of a NAAQS).

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with different length O_3 seasons receive the same degree of public health protection.

Based on analyses of forms specified in terms of an nth-highest concentration (n ranged from 3 to 5), advice from CASAC, and public comment, the Administrator concluded that a fourth-highest daily maximum should be retained (73 FR 16465, March 27, 2008). In reaching this decision, the Administrator recognized that ''there is not a clear health-based threshold for selecting a particular nth-highest daily maximum form of the standard'' and that ''the adequacy of the public health protection provided by the combination of the level and form is a foremost consideration'' (73 FR 16475, March 27, 2008). Based on this, the Administrator judged that the existing form (fourth-highest daily maximum 8-hour average concentration) should be retained, recognizing the increase in public health protection provided by combining this form with a lower standard level (*i.e.,* 75 ppb).

The Administrator also recognized that it is important to have a form that provides stability with regard to implementation of the standard. In the case of O_3, for example, he noted the importance of a form insulated from the impacts of extreme meteorological events that are conducive to O_3 formation. Such events could have the effect of reducing public health protection, to the extent they result in frequent shifts in and out of attainment due to meteorological conditions. The Administrator noted that such frequent shifting could disrupt an area's ongoing implementation plans and associated control programs (73 FR 16474, March 27, 2008). In his final decision, the Administrator judged that a fourth-high form ''provides a stable target for implementing programs to improve air quality'' (*id.* at 16475).

b. Proposed Decision on Form

In the proposal for the current review, the Administrator considered the extent to which newly available information provides support for the current form (79 FR 75293). In so doing, she took note of the conclusions of prior reviews summarized above. She recognized the value of an nth-high statistic over that of an expected exceedance or percentile-based form in the case of the O_3 standard, for the reasons summarized above. The Administrator additionally took note of the importance of stability in implementation to achieving the level of protection specified by the NAAQS. Specifically, she noted that to the extent areas engaged in implementing the O_3 NAAQS frequently shift from meeting the standard to violating the standard, it is possible that ongoing implementation plans and associated control programs could be disrupted, thereby reducing public health protection.

In light of this, while giving foremost consideration to the adequacy of public health protection provided by the combination of all elements of the standard, including the form, the Administrator considered particularly the findings from prior reviews with regard to the use of the nth-high metric. As noted above, the EPA selected the fourth-highest daily maximum, recognizing the public health protection provided by this form, when coupled with an appropriate averaging time and level, and recognizing that such a form can provide stability for implementation programs. In the proposal the Administrator concluded that the currently available evidence and information do not call into question these conclusions from previous reviews. In reaching this initial conclusion, the Administrator noted that CASAC concurred that the O_3 standard should be based on the fourth-highest, daily maximum 8-hour average value (averaged over 3 years), stating that this form ''provides health protection while allowing for atypical meteorological conditions that can lead to abnormally high ambient ozone concentrations which, in turn, provides programmatic stability'' (Frey, 2014c, p. 6). Thus, a standard with the current fourth-high form, coupled with a level lower than 75 ppb as discussed below, would be expected to increase public health protection relative to the current standard while continuing to provide stability for implementation programs. Therefore, the Administrator proposed to retain the current fourth-highest daily maximum form for an O_3 standard with an 8-hour averaging time and a revised level.

c. Public Comments on Form

Several commenters focused on the stability of the standard to support their positions regarding form. Some industry associations and state agencies support changing to a form that would allow a larger number of exceedances of the standard level than are allowed by the current fourth-high form. In some cases, these commenters argued that a standard allowing a greater number of exceedances would provide the same degree of public health protection as the current standard. Some commenters advocated a percentile-based form, such as the 98th percentile. These commenters cited a desire for consistency with short-term standards for other criteria pollutants (*e.g.,* $PM_{2.5}$, NO_2), as well as a desire to allow a greater number of exceedances of the standard level, thus making the standard less sensitive to fluctuations in background O_3 concentrations and to extreme meteorological events.

Other commenters submitted analyses purporting to indicate that a fourth-high form provides only a small increase in stability, relative to forms that allow fewer exceedances of the standard level (*i.e.,* first-high, second-high). These commenters also called into question the degree of health protection achieved by a standard with a fourth-high form and a level in the proposed range (*i.e.,* 65 to 70 ppb). They pointed out that a fourth-high form will, by definition, allow 3 days per year, on average, with 8-hour O_3 concentrations above the level of the standard. Commenters further stated that ''[i]f ozone levels on these peak days are appreciably higher than on the fourth-highest day, given EPA's acknowledged concerns regarding single or multiple (defined by EPA as 2 or more) exposures to elevated ozone concentrations, EPA must account for the degree of under-protection in setting the level of the NAAQS'' (*e.g.,* ALA *et al.,* p. 138).

For the reasons discussed in the proposal, and summarized above, the EPA disagrees with commenters who supported a percentile-based form, such as the 98th percentile, for the O_3 NAAQS. As noted above, a percentile-based statistic would not be effective in ensuring the same degree of public health protection across the country. Rather, a percentile-based form would allow more days with higher air quality values in locations with longer O_3 seasons relative to locations with shorter O_3 seasons. Thus, as in the 2008 review, in the current review the EPA concludes that a form based on the nth-highest maximum O_3 concentration would more effectively ensure that people who live in areas with different length O_3 seasons receive the same degree of public health protection.

In considering various nth-high values, as in past reviews (*e.g.,* 73 FR 16475, March 27, 2008), the EPA recognizes that there is not a clear health-based threshold for selecting a particular nth-highest daily maximum form. Rather, the primary consideration is the adequacy of the public health protection provided by the combination of all of the elements of the standard, including the form. Environmental and public health commenters are correct that a standard with the current fourth-high form will allow 3 days per year, on average, with 8-hour O_3 concentrations higher than the standard level. However, the EPA disagrees with these

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commenters' assertion that using a fourth-high form results in a standard that is under-protective. The O_3 exposure and risk estimates that informed the Administrator's consideration of the degree of public health protection provided by various standard levels were based on air quality that ''just meets'' various standards with the current 8-hour averaging time and fourth-high, 3-year average form (U.S. EPA, 2014a, section 4.3.3). Therefore, air quality adjusted to meet various levels of the standard with the current form and averaging time will include days with concentrations above the level of the standard, and these days contribute to exposure and risk estimates. In this way, the Administrator has reasonably considered the public health protection provided by the combination of all of the elements of the standard, including the fourth-high form.

In past reviews, EPA selected the fourth-highest daily maximum form in recognition of the public health protection provided by this form, when coupled with an appropriate averaging time and level, and recognizing that such a form can provide stability for ongoing implementation programs. As noted above, some commenters submitted analyses suggesting that a fourth-high form provides only a small increase in stability, relative to a first- or second-high form. The EPA has conducted analyses of ambient O_3 monitoring data to further consider these commenters' assertions regarding stability. The EPA's analyses of nth-high concentrations ranging from first-high to fifth-high have been summarized in a memo to the docket (Wells, 2015a). Consistent with commenters' analyses, Wells (2015a) indicates a progressive decrease in the variability of O_3 concentrations, and an increase in the stability of those concentrations, as ''n'' increases. Based on these analyses, there is no clear threshold for selecting a particular nth-high form based on stability alone. Rather, as in past reviews, the decision on form in this review focuses first and foremost on the Administrator's judgments on public health protection, with judgments regarding stability of the standard being a legitimate, but secondary consideration. The Administrator's final decision on form is discussed below.

d. Administrator's Final Decision Regarding Form

In reaching a final decision on the form of the primary O_3 standard, as described in the proposal and above, the Administrator recognizes that there is not a clear health-based rationale for selecting a particular nth-highest daily maximum form. Her foremost consideration is the adequacy of the public health protection provided by the combination of all of the elements of the standard, including the form. In this regard, the Administrator recognizes the support from analyses in previous reviews, and from the CASAC in the current review, for the conclusion that the current fourth-high form of the standard, when combined with a revised level as discussed below, provides an appropriate balance between public health protection and a stable target for implementing programs to improve air quality. In particular, she notes that the CASAC concurred that the O_3 standard should be based on the fourth-highest, daily maximum 8-hour average value (averaged over 3 years), stating that this form ''provides health protection while allowing for atypical meteorological conditions that can lead to abnormally high ambient ozone concentrations which, in turn, provides programmatic stability'' (Frey, 2014c, p. 6). Based on these considerations, and on consideration of public comments on form as discussed above, the Administrator judges it appropriate to retain the current fourth-high form (fourth-highest daily maximum 8-hour O_3 concentration, averaged over 3 years) in this final rule.

4. Level

This section summarizes the basis for the Administrator's proposed decision to revise the current standard level (II.C.4.a); discusses public comments, and the EPA's responses, on that proposed decision (II.C.4.b); and presents the Administrator's final decision regarding the level of the primary O_3 standard (II.C.4.c).

a. Basis for the Administrator's Proposed Decision on Level

In conjunction with her proposed decisions to retain the current indicator, averaging time, and form (II.C.1 to II.C.3, above), the Administrator proposed to revise the level of the primary O_3 standard to within the range of 65 to 70 ppb. In proposing this range of standard levels, as discussed in section II.E.4 of the proposal, the Administrator carefully considered the scientific evidence assessed in the ISA (U.S. EPA, 2013); the results of the exposure and risk assessments in the HREA (U.S. EPA, 2014a); the evidence-based and exposure-/risk-based considerations and conclusions in the PA (U.S. EPA, 2014c); CASAC advice and recommendations, as reflected in CASAC's letters to the Administrator and in public discussions of drafts of the ISA, HREA, and PA (Frey and Samet, 2012; Frey, 2014 a, c); and public input received during the development of these documents.

The Administrator's proposal to revise the standard level built upon her proposed conclusion that the overall body of scientific evidence and exposure/risk information calls into question the adequacy of public health protection afforded by the current primary O_3 standard, particularly for at-risk populations and lifestages. In reaching proposed conclusions on alternative levels for the primary O_3 standard, the Administrator considered the extent to which various alternatives would be expected to protect the public, including at-risk populations, against the wide range of adverse health effects that have been linked with short- or long-term O_3 exposures.

As was the case for her consideration of the adequacy of the current primary O_3 standard (II.B.3, above), the Administrator placed the greatest weight on the results of controlled human exposure studies and on exposure and risk analyses based on information from these studies. In doing so, she noted that controlled human exposure studies provide the most certain evidence indicating the occurrence of health effects in humans following exposures to specific O_3 concentrations. The effects reported in these studies are due solely to O_3 exposures, and interpretation of study results is not complicated by the presence of co-occurring pollutants or pollutant mixtures (as is the case in epidemiologic studies). She further noted the CASAC judgment that ''the scientific evidence supporting the finding that the current standard is inadequate to protect public health is strongest based on the controlled human exposure studies of respiratory effects'' (Frey, 2014c, p. 5).

In considering the evidence from controlled human exposure studies, the Administrator first noted that the largest respiratory effects, and the broadest range of effects, have been studied and reported following exposures to 80 ppb O_3 or higher, with most exposure studies conducted at these higher concentrations. Exposures of healthy adults to O_3 concentrations of 80 ppb or higher have been reported to decrease lung function, increase airway inflammation, increase respiratory symptoms, result in airway hyperresponsiveness, and decrease lung host defenses. The Administrator further noted that O_3 exposure concentrations as low as 72 ppb have been shown to both decrease lung function and increase respiratory

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symptoms (Schelegle *et al.*, 2009),[121] a combination that meets the ATS criteria for an adverse response, and that exposures as low as 60 ppb have been reported to decrease lung function and increase airway inflammation.

Based on this evidence, the Administrator reached the initial conclusion that the results of controlled human exposure studies strongly support setting the level of a revised O_3 standard no higher than 70 ppb. In reaching this conclusion, she placed a large amount of weight on the importance of setting the level of the standard well below 80 ppb, the exposure concentration at which the broadest range of effects have been studied and reported, and below 72 ppb, the lowest exposure concentration shown to result in the adverse combination of lung function decrements and respiratory symptoms. She placed significant weight on this *combination* of effects, as did CASAC, in making judgments regarding the potential for adverse responses.

In further considering the potential public health implications of a standard with a level of 70 ppb, the Administrator also considered quantitative estimates of the extent to which such a standard would be expected to limit population exposures to the broader range of O_3 concentrations shown in controlled human exposure studies to cause respiratory effects. In doing so, she focused on estimates of O_3 exposures of concern at or above the benchmark concentrations of 60, 70, and 80 ppb. The Administrator judged that the evidence supporting the occurrence of adverse respiratory effects is strongest for exposures at or above the 70 and 80 ppb benchmarks. Therefore, she placed a large amount of emphasis on the importance of setting a standard that limits exposures of concern at or above these benchmarks.

The Administrator expressed less confidence that adverse effects will occur following exposures to O_3 concentrations as low as 60 ppb. In reaching this conclusion, she highlighted the fact that statistically significant increases in respiratory symptoms, combined with lung function decrements, have not been reported following exposures to 60 or 63 ppb O_3, though several studies have evaluated the potential for such effects (Kim et al., 2011; Schelegle et al., 2009; Adams, 2006).[122] The proposal specifically stated that ''[t]he Administrator has decreasing confidence that adverse effects will occur following exposures to O_3 concentrations below 72 ppb. In particular, compared to O_3 exposure concentrations at or above 72 ppb, she has less confidence that adverse effects will occur following exposures to O_3 concentrations as low as 60 ppb'' (79 FR 73304–05).

However, she noted the possibility for adverse effects following such exposures given that: (1) CASAC judged the adverse combination of lung function decrements and respiratory symptoms ''almost certainly occur in some people'' following exposures to O_3 concentrations below 72 ppb (though CASAC did not specify or otherwise indicate how far below) (Frey, 2014c, p. 6); (2) CASAC indicated the moderate lung function decrements (*i.e.,* FEV_1 decrements $\geq$ 10%) that occur in some healthy adults following exposures to 60 ppb O_3 could be adverse to people with lung disease; and (3) airway inflammation has been reported following exposures as low as 60 ppb O_3. She also took note of CASAC advice that the occurrence of exposures of concern at or above 60 ppb is an appropriate consideration for people with asthma (Frey, 2014c, p. 6). Therefore, while the Administrator expressed less confidence that adverse effects will occur following exposures to O_3 concentrations as low as 60 ppb, compared to 70 ppb and above, based on the evidence and CASAC advice she also gave some consideration to exposures of concern for the 60 ppb benchmark.

Due to interindividual variability in responsiveness, the Administrator further noted that not every occurrence of an exposure of concern will result in an adverse effect, and that repeated occurrences of some of the effects demonstrated following exposures of concern could increase the likelihood of adversity (U.S. EPA, 2013, section 6.2.3). Therefore, the Administrator was most concerned about protecting at-risk populations against repeated occurrences of exposures of concern. Based on the above considerations, the Administrator focused on the extent to which a revised standard with a level of 70 ppb would be expected to protect populations from experiencing two or more O_3 exposures of concern (*i.e.,* as a surrogate for repeated exposures).

As illustrated in Table 1 in the proposal (and Table 1 above), the Administrator noted that, in urban study areas, a revised standard with a level of 70 ppb is estimated to eliminate the occurrence of two or more exposures of concern to O_3 concentrations at and above 80 ppb and to virtually eliminate the occurrence of two or more exposures of concern to O_3 concentrations at and above 70 ppb, even in the worst-case urban study area and year evaluated. Though the Administrator acknowledged greater uncertainty with regard to the occurrence of adverse effects following exposures to 60 ppb, she noted that a revised standard with a level of 70 ppb would also be expected to protect the large majority of children in the urban study areas (*i.e.,* about 96% to more than 99% of children in individual urban study areas) from experiencing two or more exposures of concern at or above the 60 ppb benchmark. Compared to the current standard, this represents a reduction of more than 60%.[123]

In further evaluating the potential public health impacts of a standard with a level of 70 ppb, the Administrator also considered the HREA estimates of O_3-induced lung function decrements. To inform her consideration of these decrements, the Administrator took note of CASAC advice that ''estimation of FEV_1 decrements of $\geq$ 15% is appropriate as a scientifically relevant surrogate for adverse health outcomes in active healthy adults, whereas an FEV_1 decrement of $\geq$ 10% is a scientifically relevant surrogate for adverse health outcomes for people with asthma and lung disease'' (Frey, 2014c, p. 3).

Although these FEV_1 decrements provide perspective on the potential for the occurrence of adverse respiratory effects following O_3 exposures, the Administrator agreed with the conclusion in past reviews that a more general consensus view of the adversity of moderate responses emerges as the frequency of occurrence increases (61 FR 65722–3, Dec, 13, 1996). Specifically, she judged that not every estimated occurrence of an O_3-induced FEV_1 decrement will be adverse and

[121] As noted above, for the 70 ppb target exposure concentration, Schelegle *et al.* (2009) reported that the actual mean exposure concentration was 72 ppb.

[122] In the study by Schelegle, for the 60 ppb target exposure concentration, study authors reported that the actual mean exposure concentration was 63 ppb.

[123] The Administrator judged that the evidence is less compelling, and indicates greater uncertainty, with regard to the potential for adverse effects following single occurrences of O_3 exposures of concern. While acknowledging this greater uncertainty, she noted that a standard with a level of 70 ppb would also be expected to virtually eliminate all occurrences (including single occurrences) of exposures of concern at or above 80 ppb, even in the worst-case year and location. She also judged that such a standard will achieve important reductions, compared to the current standard, in the occurrence of one or more exposures of concern at or above 70 and 60 ppb.

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that repeated occurrences of moderate responses could lead to more serious illness. Therefore, the Administrator noted increasing concern about the potential for adversity as the number of occurrences increases and, as a result, she focused primarily on estimates of two or more O_3-induced FEV_1 decrements (*i.e.,* as a surrogate for repeated exposures).[124]

The Administrator noted that a revised O_3 standard with a level of 70 ppb is estimated to protect about 98 to 99% of children in urban study areas from experiencing two or more O_3-induced FEV_1 decrements ≥15%, and about 89 to 94% from experiencing two or more decrements ≥10%. She judged that these estimates reflect important risk reductions, compared to the current standard. Given these estimates, as well as estimates of one or more decrements per season (about which she was less concerned (79 FR 75290, December 17, 2014)), the Administrator concluded that a revised standard with a level of 70 ppb would be expected to provide substantial protection against the risk of O_3-induced lung function decrements, and would be expected to result in important reductions in such risks, compared to the current standard. The Administrator further noted, however, that the variability in lung function risk estimates across urban study areas is often greater than the differences in risk estimates between various standard levels (Table 2, above). Given this, and the resulting considerable overlap between the ranges of lung function risk estimates for different standard levels, in the proposal the Administrator viewed lung function risk estimates as providing a more limited basis than exposures of concern for distinguishing between the degrees of public health protection provided by alternative standard levels (79 FR 75306 n. 164).

In next considering the additional protection that would be expected from standard levels below 70 ppb, the Administrator evaluated the extent to which a standard with a level of 65 ppb would be expected to further limit O_3 exposures of concern and O_3-induced lung function decrements. In addition to eliminating almost all exposures of concern to O_3 concentrations at or above 80 and 70 ppb, even in the worst-case years and locations, the Administrator noted that a revised standard with a level of 65 ppb would be expected to protect more than 99% of children in urban study areas from experiencing two or more exposures of concern at or above 60 ppb and to substantially reduce the occurrence of one or more such exposures, compared to the current standard. With regard to O_3-induced lung function decrements, an O_3 standard with a level of 65 ppb is estimated to protect about 98% to more than 99% of children from experiencing two or more O_3-induced FEV_1 decrements ≥15% and about 91 to 99% from experiencing two or more decrements ≥10%.[125]

Taken together, the Administrator concluded that the evidence from controlled human exposure studies, and the information from quantitative analyses that draw upon these studies, provide strong support for standard levels from 65 to 70 ppb. In particular, she based this conclusion on the fact that such standard levels would be well below the O_3 exposure concentration shown to result in the widest range of respiratory effects (*i.e.,* 80 ppb),[126] and below the lowest O_3 exposure concentration shown to result in the adverse combination of lung function decrements and respiratory symptoms (*i.e.,* 72 ppb). A standard with a level from 65 to 70 ppb would also be expected to result in important reductions, compared to the current standard, in the occurrence of O_3 exposures of concern for all of the benchmarks evaluated (*i.e.,* 60, 70, and 80 ppb) and in the risk of O_3-induced lung function decrements ≥10 and 15%.

In further considering the evidence and exposure/risk information, the Administrator considered the extent to which the epidemiologic evidence also provides support for standard levels from 65 to 70 ppb. In particular, the Administrator noted analyses in the PA (U.S. EPA, 2014c, section 4.4.1) indicating that a revised standard with a level of 65 or 70 ppb would be expected to maintain distributions of short-term ambient O_3 concentrations below those present in the locations of all the single-city epidemiologic studies of hospital admissions or emergency department visits analyzed. She concluded that a revised standard with a level at least as low as 70 ppb would result in improvements in public health, beyond the protection provided by the current standard, in the locations of the single-city epidemiologic studies that reported significant health effect associations.[127]

The Administrator noted additional uncertainty in interpreting air quality in locations of multicity epidemiologic studies of short-term O_3 for the purpose of evaluating alternative standard levels (II.D.1 and U.S. EPA, 2014c, section 4.4.1). While acknowledging this uncertainty, and therefore placing less emphasis on these analyses of study location air quality, she noted that PA analyses suggest that standard levels of 65 or 70 ppb would require reductions, beyond those required by the current standard, in ambient O_3 concentrations present in several of the locations that provided the basis for statistically significant O_3 health effect associations in multicity studies.

In further evaluating information from epidemiologic studies, the Administrator considered the HREA's epidemiology-based risk estimates for O_3-associated morbidity or mortality (U.S. EPA, 2014a, Chapter 7). Compared to the weight given to the evidence from controlled human exposure studies, and to HREA estimates of exposures of concern and lung function risks, she placed relatively less weight on epidemiology-based risk estimates. In doing so, she noted that the overall conclusions from the HREA likewise reflect relatively less confidence in estimates of epidemiology-based risks than in estimates of exposures of concern and lung function risks.

In considering epidemiology-based risk estimates, the Administrator focused on risks associated with O_3 concentrations in the upper portions of ambient distributions, given the greater uncertainty associated with the shapes of concentration-response curves for O_3 concentrations in the lower portions of ambient distributions (*i.e.,* below about 20 to 40 ppb depending on the O_3 metric, health endpoint, and study population) (U.S. EPA, 2013, section 2.5.4.4). The Administrator further noted that experimental studies provide the strongest evidence for O_3-induced effects following exposures to O_3 concentrations corresponding to the upper portions of typical ambient

[124] In the proposal, the Administrator further judged that it would not be appropriate to set a standard that is intended to eliminate all O_3-induced FEV_1 decrements. She noted that this is consistent with CASAC advice, which did not include a recommendation to set the standard level low enough to eliminate all O_3-induced FEV_1 decrements ≥ 10 or 15% (Frey, 2014c).

[125] Although the Administrator was less concerned about the public health implications of single O_3-induced lung function decrements, she also noted that a revised standard with a level of 65 ppb is estimated to reduce the risk of one or more O_3-induced decrements per season, compared to the current standard.

[126] Although the widest range of effects have been evaluated following exposures to 80 ppb O_3, there is no evidence that 80 ppb is a threshold for these effects.

[127] The Administrator also concluded that analyses in the HREA and PA indicate that a standard with an 8-hour averaging time, coupled with the current fourth-high form and a level from 65 to 70 ppb, would be expected to provide increased protection, compared to the current standard, against the long-term O_3 concentrations that have been reported to be associated with respiratory morbidity or mortality (79 FR 75293; 75308).

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distributions. In particular, as discussed above, she noted controlled human exposure studies showing respiratory effects following exposures to O_3 concentrations at or above 60 ppb (79 FR 75308, December 17, 2014). Therefore, in considering risks associated with O_3 concentrations in the upper portions of ambient distributions, the Administrator focused on the extent to which revised standards with levels of 70 or 65 ppb are estimated to reduce the risk of premature deaths associated with area-wide O_3 concentrations at or above 40 ppb and 60 ppb.

Given all of the above evidence, exposure/risk information, and advice from CASAC, the Administrator proposed to revise the level of the current primary O_3 standard to within the range of 65 to 70 ppb. In considering CASAC advice on the range of standard levels, the Administrator placed a large amount of weight on CASAC's conclusion that there is adequate scientific evidence to consider a range of levels for a primary standard that includes an upper end at 70 ppb. She also noted that although CASAC expressed concern about the margin of safety at a level of 70 ppb, it further acknowledged that the choice of a level within the range recommended based on scientific evidence is a policy judgment (Frey, 2014c, p. ii). While she agreed with CASAC that it is appropriate to consider levels below 70 ppb, as reflected in her range of proposed levels from 65 to 70 ppb, for the reasons discussed above she also concluded that a standard level as high as 70 ppb, which CASAC concluded could be supported by the scientific evidence, could reasonably be judged to be requisite to protect public health with an adequate margin of safety.

In considering the appropriateness of standard levels below 65 ppb, the Administrator noted the conclusions of the PA and the advice of CASAC that it would be appropriate for her to consider standard levels as low as 60 ppb. In making the decision to not propose levels below 65 ppb, she focused on CASAC's rationale for a level of 60 ppb, which focused on the importance of limiting exposures to O_3 concentrations as low as 60 ppb (Frey, 2014c, p. 7). As discussed above, the Administrator agreed that it is appropriate to consider the implications of a revised standard level for estimated exposures of concern at or above 60 ppb. She noted that standards within the proposed range of 65 to 70 ppb would be expected to substantially limit the occurrence of exposures of concern to O_3 concentrations at or above 60 ppb, particularly the occurrence of two or more exposures. When she further considered that not all exposures of concern lead to adverse effects, and that the NAAQS are not meant to be zero-risk or background standards, the Administrator judged that alternative standard levels below 65 ppb are not needed to further reduce such exposures.

b. Comments on Level

A number of groups representing medical, public health, or environmental organizations; some state agencies; and many individuals submitted comments on the appropriate level of a revised primary O_3 standard.[128] Virtually all of these commenters supported setting the standard level within the range recommended by CASAC (*i.e.,* 60 to 70). Some expressed support for the overall CASAC range, without specifying a particular level within that range, while others expressed a preference for the lower part of the CASAC range, often emphasizing support for a level of 60 ppb. Some of these commenters stated that if the EPA does not set the level at 60 ppb, then the level should be set no higher than 65 ppb (*i.e.,* the lower bound of the proposed range of standard levels).

To support their views on the level of a revised standard, some commenters focused on overarching issues related to the statutory requirements for the NAAQS. For example, some commenters maintained that the primary NAAQS must be set at a level at which there is an absence of adverse effects in sensitive populations. While this argument has some support in the case law and in the legislative history to the 1970 CAA (see *Lead Industries Ass'n* v. *EPA,* 647 F. 2d 1147, 1153 (D.C. Cir. 1980)), it is well established that the NAAQS are not meant to be zero risk standards. See *Lead Industries* v. *EPA,* 647 F.2d at 1156 n.51; *Mississippi* v. *EPA,* 744 F. 3d at 1351. From the inception of the NAAQS standard-setting process, the EPA and the courts have acknowledged that scientific uncertainties in general, and the lack of clear thresholds in pollutant effects in particular, preclude any such definitive determinations. *Lead Industries,* 647 F. 2d at 1156 (setting standard at a level which would remove most but not all sub-clinical effects). Likewise, the House report to the 1977 amendments addresses this question (H. Rep. 95–294, 95th Cong. 1st sess. 127): [129]

> Some have suggested that since the standards are to protect against all known or anticipated effects and since no safe threshold can be established, the ambient standards should be set at zero or background levels. Obviously, this no-risk philosophy ignores all economic and social consequences and is impractical. This is particularly true in light of the legal requirement for mandatory attainment of the national primary standards within 3 years.

Thus, post-1970 jurisprudence makes clear the impossibility, and lack of legal necessity, for NAAQS removing all health risk. See *ATA III,* 283 F. 3d at 360 (''[t]he lack of a threshold concentration below which these pollutants are known to be harmless makes the task of setting primary NAAQS difficult, as EPA must select standard levels that reduce risks sufficiently to protect public health even while recognizing that a zero-risk standard is not possible''); *Mississippi,* 744 F. 3d at 1351 (same); see also *id.* at 1343 (''[d]etermining what is 'requisite' to protect the 'public health' with an 'adequate' margin of safety may indeed require a contextual assessment of acceptable risk. See *Whitman,* 531 U.S. at 494–95 (Breyer J. concurring)'').

In this review, EPA is setting a standard based on a careful weighing of available evidence, including a weighing of the strengths and limitations of the evidence and underlying scientific uncertainties therein. The Administrator's choice of standard level is rooted in her evaluation of the evidence, which reflects her legitimate uncertainty as to the O_3 concentrations at which the public would experience adverse health effects. This is a legitimate, and well recognized, exercise of ''reasoned decision-making.'' *ATA III.* 283 F. 3d at 370; see also id. at 370 (''EPA's inability to guarantee the accuracy or increase the precision of the . . . NAAQS in no way undermines the standards' validity. Rather, these limitations indicate only that significant scientific uncertainty remains about the health effects of fine particulate matter at low atmospheric concentration. ....''); *Mississippi,* 744 F. 3d at 1352–53 (appropriate for EPA to balance scientific uncertainties in determining level of revised O_3 NAAQS).

[128] ~~In general,~~ commenters who expressed the view that the EPA should retain the current O_3 NAAQS (*i.e.,* commenters representing industry and business groups, and some states) did not provide comments on alternative standard levels. As a result, this section focuses primarily on comments from commenters who expressed support for the proposed decision to revise the current primary O_3 standard.

[129] Similarly, Senator Muskie remarked during the floor debates on the 1977 Amendments that ''there is no such thing as a threshold for health effects. Even at the national primary standard level, which is the health standard, there are health effects that are not protected against''. 123 Cong. Rec. S9423 (daily ed. June 10, 1977).

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In an additional overarching comment, some commenters also fundamentally objected to the EPA's consideration of exposure estimates in reaching conclusions on the primary O_3 standard. These commenters' general assertion was that NAAQS must be established so as to be protective, with an adequate margin of safety, regardless of the activity patterns that feed into exposure estimates. They contended that ''[a]ir quality standards cannot rely on avoidance behavior in order to protect the public health and sensitive groups'' and that ''[i]t would be unlawful for EPA to set the standard at a level that is contingent upon people spending most of their time indoors'' (*e.g.,* ALA *et al*., p. 124). To support these comments, for example, ALA *et al.* analyzed ambient monitoring data from Core-Based Statistical Areas (CBSAs) with design values between 66–70 ppb (Table 17, pp. 145–151 in ALA *et al.*) and 62–65 ppb (Table 18, pp. 153–154 in ALA et al.) and pointed out that there are many more days with ambient concentrations above the benchmark levels than were estimated in the EPA's exposure analysis (*i.e.,* at and above the benchmark level of 60, 70 and 80 ppb).

The EPA disagrees with these commenters' conclusions regarding the appropriateness of considering exposure estimates, and notes that NAAQS must be ''requisite'' (*i.e.,* ''sufficient, but not more than necessary'' (*Whitman,* 531 U.S. at 473)) to protect the ''public health'' (''the health of the public'' (*Whitman,* 531 U.S. at 465)). Estimating exposure patterns based on extensive available data [130] is a reasonable means of ascertaining that standards are neither under- nor over-protective, and that standards address issues of public health rather than health issues pertaining only to isolated individuals.[131] Behavior patterns are critical in assessing whether ambient concentrations of O_3 may pose a public health risk.[132] Exposures to ambient or near-ambient O_3 concentrations have only been shown to result in potentially adverse effects if the ventilation rates of people in the exposed populations are raised to a sufficient degree (*e.g.,* through physical exertion) (U.S. EPA, 2013, section 6.2.1.1).[133] Ignoring whether such elevated ventilation rates are actually occurring, as advocated by these commenters, would not provide an accurate assessment of whether the public health is at risk. Indeed, a standard established without regard to behavior of the public would likely lead to a standard which is more stringent than necessary to protect the public health.

While setting the primary O_3 standard based only on ambient concentrations, without consideration of activity patterns and ventilation rates, would likely result in a standard that is over-protective, the EPA also concludes that setting a standard based on the assumption that people will adjust their activities to avoid exposures on high-pollution days would likely result in a standard that is under-protective. The HREA's exposure assessment does not make this latter assumption.[134] The time-location-activity diaries that provided the basis for exposure estimates reflect actual variability in human activities. While some diary days may reflect individuals spending less time outdoors than would be typical for them, it is similarly likely that some days reflect individuals spending more time outdoors than would be typical. Considering the actual variability in time-location-activity patterns is at the least a permissible way of identifying standards that are neither over- nor under-protective.[135]

Further, the EPA sees nothing in the CAA that prohibits consideration of the O_3 exposures that could result in effects of public health concern. While a number of judicial opinions have upheld the EPA's decisions in other NAAQS reviews to place little weight on particular risk or exposure analyses (*i.e.,* because of scientific uncertainties in those analyses), none of these opinions have suggested that such analyses are irrelevant because actual exposure patterns do not matter. See, *e.g. Mississippi,* 744 F. 3d at 1352–53; *ATA III,* 283 F. 3d at 373–74. Therefore, because behavior patterns are critical in assessing whether ambient concentrations of O_3 may pose a public health risk, the EPA disagrees with the views expressed by these commenters objecting to the consideration of O_3 exposures in reaching decisions on the primary O_3 standard.

In addition to these overarching comments, a number of commenters supported their views on standard level by highlighting specific aspects of the scientific evidence, exposure/risk information, and/or CASAC advice. Key themes expressed by these commenters included the following: (1) Controlled human exposure studies provide strong evidence of adverse lung function decrements and airway inflammation in healthy adults following exposures to O_3 concentrations as low as 60 ppb, and at-risk populations would be likely to experience more serious effects or effects at even lower concentrations; (2) epidemiologic studies provide strong evidence for associations with mortality and morbidity in locations with ambient O_3 concentrations below 70 ppb, and in many cases in locations with concentrations near and below 60 ppb; (3) quantitative analyses in the HREA are biased such that they understate O_3 exposures and risks, and the EPA's interpretation of lung function risk estimates is not appropriate and not consistent with other NAAQS; and (4) the EPA must give deference to CASAC advice, particularly CASAC's policy advice to set the standard level below 70 ppb. The next sections discuss comments related to each of these points, and provide the EPA's responses to those comments. More detailed discussion of individual comments, and the EPA's responses, is provided in the Response to Comments document.

i. Effects in Controlled Human Exposure Studies

Some commenters who advocated for a level of 60 ppb (or absent that, for 65 ppb) asserted that controlled human exposure studies have reported adverse respiratory effects in healthy adults following exposures to O_3 concentrations as low as 60 ppb. These commenters generally based their conclusions on the demonstration of FEV_1 decrements ≥ 10% and increased airway inflammation following exposures of healthy adults to 60 ppb O_3. They concluded that even more serious effects would occur in at-risk

[130] The CHAD database used in the HREA's exposure assessment contains over 53,000 individual daily diaries including time-location-activity patterns for individuals of both sexes across a wide range of ages (U.S. EPA, 2014a, Chapter 5).

[131] CASAC generally agreed with the EPA's methodology for characterizing exposures of concern (Frey, 2014a, pp. 5–6).

[132] See 79 FR 75269 (''The activity pattern of individuals is an important determinant of their exposure. Variation in O_3 concentrations among various microenvironments means that the amount of time spent in each location, as well as the level of activity, will influence an individual's exposure to ambient O_3. Activity patterns vary both among and within individuals, resulting in corresponding variations in exposure across a population and over time'' (internal citations omitted).

[133] For healthy young adults exposed at rest for 2 hours, 500 ppb is the lowest O_3 concentration reported to produce a statistically significant O_3-induced group mean FEV_1 decrement (U.S. EPA, 2013, section 6.2.1.1).

[134] The EPA was aware of the possibility of averting behavior during the development of the HREA, and that document includes sensitivity analyses to provide perspective on the potential role of averting behavior in modifying O_3 exposures. As discussed further above (II.B.2.c), these sensitivity analyses were limited and the results were discussed in the proposal within the context of uncertainties in the HREA assessment of exposures of concern.

[135] See *Mississippi,* 744 F. 3d at 1343 (''[d]etermining what is 'requisite' to protect the 'public health' with an 'adequate' margin of safety may indeed require a contextual assessment of acceptable risk. See *Whitman,* 531 U.S. at 494–95 (Breyer, J. concurring . . .))''

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populations exposed to 60 ppb O_3, and that such populations would experience adverse effects following exposures to O_3 concentrations below 60 ppb.

While the EPA agrees that information from controlled human exposure studies conducted at 60 ppb can help to inform the Administrator's decision on the standard level, the Agency does not agree that this information necessitates a level below 70 ppb. In fact, as discussed in the proposal, a revised O_3 standard with a level of 70 ppb can be expected to provide substantial protection against the effects shown to occur following various O_3 exposure concentrations, including those observed following exposures to 60 ppb. This is because the degree of protection provided by any NAAQS is due to the combination of all of the elements of the standard (*i.e.,* indicator, averaging time, form, level). In the case of the fourth-high form of the O_3 NAAQS, which the Administrator is retaining in the current review (II.C.3), the large majority of days in areas that meet the standard will have 8-hour O_3 concentrations below the level of the standard, with most days well below the level. Therefore, as discussed in the proposal, in considering the degree of protection provided by an O_3 standard with a particular level, it is important to consider the extent to which that standard would be expected to limit population exposures of concern to the broader range of O_3 exposure concentrations shown in controlled human exposure studies to result in health effects. The Administrator's consideration of such exposures of concern is discussed below (II.C.4.c).

Another important part of the Administrator's consideration of exposure estimates is the extent to which she judges that adverse effects could occur following specific O_3 exposures. While controlled human exposure studies provide a high degree of confidence regarding the extent to which specific health effects occur following exposures to O_3 concentrations from 60 to 80 ppb, the Administrator notes that there are no universally accepted criteria by which to judge the adversity of the observed effects. Therefore, in making judgments about the extent to which the effects observed in controlled human exposure studies have the potential to be adverse, the Administrator considers the recommendations of ATS and advice from CASAC (II.A.1.c, above).

As an initial matter, with regard to the effects shown in controlled human exposure studies following O_3 exposures, the Administrator notes the following:

1. The largest respiratory effects, and the broadest range of effects, have been studied and reported following exposures to 80 ppb O_3 or higher, with most exposure studies conducted at these higher concentrations. Specifically, 6.6-hour exposures of healthy young adults to 80 ppb O_3, while engaged in quasi-continuous, moderate exertion, can decrease lung function, increase airway inflammation, increase respiratory symptoms, result in airway hyperresponsiveness, and decrease lung host defenses.

2. Exposures of healthy young adults for 6.6 hours to O_3 concentrations as low as 72 ppb, while engaged in quasi-continuous, moderate exertion, have been shown to both decrease lung function and result in respiratory symptoms.

3. Exposures of healthy young adults for 6.6 hours to O_3 concentrations as low as 60 ppb, while engaged in quasi-continuous, moderate exertion, have been shown to decrease lung function and to increase airway inflammation.

To inform her judgments on the potential adversity to public health of these effects reported in controlled human exposure studies, as in the proposal, the Administrator considers the ATS recommendation that ''reversible loss of lung function in combination with the presence of symptoms should be considered adverse'' (ATS, 2000a). She notes that this combination of effects has been shown to occur following 6.6-hour exposures to O_3 concentrations at or above 72 ppb. In considering these effects, CASAC observed that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5).

Regarding the potential for adverse effects following exposures to lower concentrations, the Administrator notes the CASAC judgment that the adverse combination of lung function decrements and respiratory symptoms ''almost certainly occur in some people'' following exposures to O_3 concentrations below 72 ppb (Frey, 2014c, p. 6). In particular, when commenting on the extent to which the study by Schelegle et al. (2009) suggests the potential for adverse effects following O_3 exposures below 72 ppb, CASAC judged that:

> [I]f subjects had been exposed to ozone using the 8-hour averaging period used in the standard [rather than the 6.6-hour exposures evaluated in the study], adverse effects could have occurred at lower concentration. Further, in our judgment, the level at which adverse effects might be observed would likely be lower for more sensitive subgroups, such as those with asthma (Frey, 2014c, p. 5).

Though CASAC did not provide advice as to how far below 72 ppb adverse effects would likely occur, the Administrator agrees that such effects could occur following exposures at least somewhat below 72 ppb.

The Administrator notes that while adverse effects could occur following exposures at least somewhat below 72 ppb, the combination of statistically significant increases in respiratory symptoms and decrements in lung function has not been reported following 6.6-hour exposures to average O_3 concentrations of 60 ppb or 63 ppb, though studies have evaluated the potential for such effects (Adams, 2006; Schelegle *et al.*, 2009; Kim *et al.*, 2011). In the absence of this combination, the Administrator looks to additional ATS recommendations and CASAC advice in order to inform her judgments regarding the potential adversity of the effects that have been observed following O_3 exposures as low as 60 ppb.

With regard to ATS, she first notes the recommendations that ''a small, transient loss of lung function, by itself, should not automatically be designated as adverse'' and that ''[f]ew . . . biomarkers have been validated sufficiently that their responses can be used with confidence to define the point at which a response should be equated to an adverse effect warranting preventive measures'' (ATS, 2000a).[136] Based on these recommendations, compared to effects following exposures at or above 72 ppb, the Administrator has less confidence in the adversity of the respiratory effects that have been observed following exposures to 60 or 63 ppb.

She further notes that some commenters who advocated for a level of 60 ppb also focused on ATS recommendations regarding population-level risks. These commenters specifically stated that lung function decrements ''may be adverse in terms of 'population risk,' where exposure to air pollution increases the risk to the population even though it might not harm lung function to a degree that is, on its own, 'clinically important' to an individual'' (*e.g.,* ALA *et al.*, p. 118). These commenters asserted that the EPA

[136] With regard to this latter recommendation, as discussed above (II.A.1.c), the ATS concluded that elevations of biomarkers such as cell numbers and types, cytokines, and reactive oxygen species may signal risk for ongoing injury and more serious effects or may simply represent transient responses, illustrating the lack of clear boundaries that separate adverse from nonadverse events.

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has not appropriately considered the potential for such population-level risk. Contrary to the views expressed by these commenters, the Administrator carefully considers the potential for population risk, particularly within the context of the ATS recommendation that "a shift in the risk factor distribution, and hence the risk profile of the exposed population, should be considered adverse, even in the absence of the immediate occurrence of frank illness'' (ATS, 2000a). Given that exposures to 60 ppb O_3 have been shown in controlled human exposure studies to cause transient and reversible decreases in group mean lung function, the Administrator notes the potential for such exposures to result in similarly transient and reversible shifts in the risk profile of an exposed population. However, in contrast to commenters who advocated for a level of 60 ppb, the Administrator also notes that the available evidence does not provide information on the extent to which a short-term, transient decrease in lung function in a population, as opposed to a longer-term or permanent decrease, could affect the risk of other, more serious respiratory effects (*i.e.,* change the risk profile of the population). This uncertainty, together with the additional ATS recommendations noted above, indicates to the Administrator that her judgment that there is uncertainty in the adversity of the effects shown to occur at 60 ppb is consistent with ATS recommendations.[137]

With regard to CASAC advice, the Administrator notes that, while CASAC clearly advised the EPA to consider the health effects shown to occur following exposures to 60 ppb O_3, its advice regarding the adversity of those effects is less clear. In particular, she notes that CASAC was conditional about whether the lung function decrements observed in some people at 60 ppb (*i.e.,* FEV_1 decrements ≥ 10%) are adverse. Specifically, CASAC stated that these decrements ''*could* be adverse in individuals with lung disease'' (Frey, 2014c, p. 7, emphasis added) and that they provide a ''*surrogate* for adverse health outcomes for people with asthma and lung disease'' (Frey, 2014c, p. 3, emphasis added). Further, CASAC did not recommend considering standard levels low enough to eliminate O_3-induced FEV_1 decrements ≥ 10% (Frey, 2014c). With regard to the full range of effects shown to occur at 60 ppb (*i.e.,* FEV_1 decrements, airway inflammation), CASAC stated that exposures of concern for the 60 ppb benchmark are ''*relevant for consideration''* with respect to people with asthma (Frey, 2014c, p. 6, italics added). In addition, ''[t]he CASAC concurs with EPA staff regarding the finding based on scientific evidence that a level of 60 ppb corresponds to the lowest exposure concentration demonstrated to result in lung function decrements large enough to be judged an abnormal response by ATS and that *could be adverse* in individuals with lung disease'' (Frey, 2014c, p. 7, italics added). The Administrator contrasts these statements with CASAC's clear advice that ''the combination of decrements in FEV_1 together with the statistically significant alterations in symptoms in human subjects exposed to 72 ppb ozone meets the American Thoracic Society's definition of an adverse health effect'' (Frey, 2014c, p. 5).

Based on her consideration of all of the above recommendations and advice noted above, the Administrator judges that, compared to exposure concentrations at and above 72 ppb, there is greater uncertainty with regard to the adversity of effects shown to occur following O_3 exposures as low as 60 ppb. However, based on the effects that have been shown to occur at 60 ppb (*i.e.,* lung function decrements, airway inflammation), and CASAC advice indicating the importance of considering these effects (though its advice regarding the adversity of effects at 60 ppb is less clear), she concludes that it is appropriate to give some consideration to the extent to which a revised standard could allow such effects.

In considering estimates of exposures of concern for the 60, 70, and 80 ppb benchmarks within the context of her judgments on adversity, the Administrator notes that, due to interindividual variability in responsiveness, not every occurrence of an exposure of concern will result in an adverse effect. As discussed above (II.B.2.b.i), this point was highlighted by some commenters who opposed revision of the current standard, based on their analysis of effects shown to occur following exposures to 72 ppb O_3. This point was also highlighted by some commenters who advocated for a level of 60 ppb, based on the discussion of O_3-induced inflammation in the proposal. In particular, this latter group of commenters highlighted discussion from the proposal indicating that ''[i]nflammation induced by a single O_3 exposure can resolve entirely but, as noted in the ISA (U.S. EPA, 2013, p. 6–76), 'continued acute inflammation can evolve into a chronic inflammatory state''' (*e.g.,* ALA *et al.*, p. 48). Consistent with these comments, and with her consideration of estimated exposurs of concern in the proposal, the Administrator judges that the types of respiratory effects that can occur following exposures of concern, particularly if experienced repeatedly, provide a plausible mode of action by which O_3 may cause other more serious effects. Because of this, as in the proposal, the Administrator is most concerned about protecting against repeated occurrences of exposures of concern.

The Administrator's consideration of estimated exposures of concern is discussed in more detail below (II.C.4.b.iv, II.C.4.c). In summary, contrary to the conclusions of commenters who advocated for a level of 60 ppb, the Administrator judges that a revised standard with a level of 70 ppb will effectively limit the occurrence of the O_3 exposures for which she is most confident in the adversity of the resulting effects (*i.e.,* based on estimates for the 70 and 80 ppb benchmarks). She further concludes that such a standard will provide substantial protection against the occurrence of O_3 exposures for which there is greater uncertainty in the adversity of effects (*i.e.,* based on estimates for the 60 ppb benchmark).

As noted above, commenters also pointed out that benchmark concentrations are based on studies conducted in healthy adults, whereas at-risk populations are likely to experience more serious effects and effects at lower O_3 exposure concentrations. In considering this issue, the EPA notes CASAC's endorsement of 60 ppb as the lower end of the range of benchmarks for evaluation, and its advice that ''the 60 ppb-8hr exposure benchmark is relevant for consideration with respect to adverse effects on asthmatics'' (Frey, 2014c, p. 6). As discussed in detail below (II.C.4.c), the Administrator has carefully considered estimated exposures of concern for the 60 ppb benchmark. In addition, though the available information does not support the identification of specific benchmarks below 60 ppb that could be appropriate for consideration for at-risk populations, and though CASAC did not recommend consideration of any such benchmarks, the EPA expects that a revised standard with a level of 70 ppb will also reduce the occurrence of exposures to O_3 concentrations at least somewhat below 60 ppb (U.S. EPA,

[137] ATS provided additional recommendations to help inform judgments regarding the adversity of air pollution-related effects (*e.g.,* related to ''quality of life''), though it is not clear whether, or how, such recommendations should be applied to the respiratory effects observed in controlled human exposure studies following 6.6-hour O_3 exposures (ATS, 200a, p. 672).

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2014a, Figures 4–9 and 4–10).[138] Thus, even if some members of at-risk populations may experience effects following exposures to O_3 concentrations somewhat below 60 ppb, a revised level of 70 ppb would be expected to reduce the occurrence of such exposures.[139] Therefore, the EPA has considered O_3 exposures that could be relevant for at-risk populations such as children and people with asthma, and does not agree that controlled human exposure studies reporting respiratory effects in healthy adults following exposures to 60 ppb O_3 necessitate a standard level below 70 ppb.

ii. Epidemiologic Studies

Commenters representing environmental and public health organizations also highlighted epidemiologic studies that, in their view, provide strong evidence for associations with mortality and morbidity in locations with ambient O_3 concentrations near and below 60 ppb. These commenters focused both on the epidemiologic studies evaluated in the PA's analyses of study location air quality (U.S. EPA, 2014c, Chapter 4) and on studies that were not explicitly analyzed in the PA, and in some cases on studies that were not included in the ISA.

The EPA agrees that epidemiologic studies can provide perspective on the degree to which O_3-associated health effects have been identified in areas with air quality likely to have met various standards. However, as discussed below, we do not agree with the specific conclusions drawn by these commenters regarding the implications of epidemiologic studies for the standard level. As an initial matter in considering epidemiologic studies, the EPA notes its decision, consistent with CASAC advice, to place the most emphasis on information from controlled human exposure studies (II.B.2 and II.B.3, above). This decision reflects the greater certainty in using information from controlled human exposure studies to link specific O_3 exposures with health effects, compared to using air quality information from epidemiologic studies of O_3 for this purpose.

While being aware of the uncertainties discussed above (II.B.2.b.ii), in considering what epidemiologic studies can tell us, the EPA notes analyses in the PA (U.S. EPA, 2014c, section 4.4.1) indicating that a revised standard with a level at or below 70 ppb would be expected to maintain distributions of short-term ambient O_3 concentrations below those present in the locations of all of the single-city epidemiologic studies analyzed. As discussed in the PA (U.S. EPA, 2014c, section 4.4.1), this includes several single-city studies conducted in locations that would have violated the current standard, and the study by Mar and Koenig (2009) that reported positive and statistically significant associations with respiratory emergency department visits with children and adults in a location that would have met the current standard over the entire study period, but would have violated a standard with a level of 70 ppb.[140] While these analyses provide support for a level at least as low as 70 ppb, the Administrator judges that they do not provide a compelling basis for distinguishing between the appropriateness of 70 ppb and lower standard levels.

As in the proposal, the EPA acknowledges additional uncertainty in interpreting air quality in locations of multicity epidemiologic studies of short-term O_3 for the purpose of evaluating alternative standard levels (U.S. EPA, 2014c, sections 3.1.4.2, 4.4.1). In particular, the PA concludes that interpretation of such air quality information is complicated by uncertainties in the extent to which multicity effect estimates (*i.e.,* which are based on combining estimates from multiple study locations) can be attributed to ambient O_3 in the subset of study locations that would have met a particular standard, versus O_3 in the study locations that would have violated the standard. While giving only limited weight to air quality analyses in these study areas because of this uncertainty, the EPA also notes PA analyses indicating that a standard level at or below 70 ppb would require additional reductions, beyond those required by the current standard, in the ambient O_3 concentrations that provided the basis for statistically significant O_3 health effect associations in multicity epidemiologic studies. As was the case for the single-city studies, and contrary to the views expressed by the commenters noted above, the Administrator judges that these studies do not provide a compelling basis for distinguishing between the appropriateness of alternative standard levels at or below 70 ppb.

In some cases, commenters highlighted studies that were assessed in the 2008 review of the O_3 NAAQS, but were not included in the ISA in the current review. These commenters asserted that such studies support the occurrence of O_3 health effect associations in locations with air quality near or, in some cases, below 60 ppb. Specifically, commenters highlighted a number of studies included in the 2007 Staff Paper that were not included in the ISA, claiming that these studies support a standard level below 70 ppb, and as low as 60 ppb.

As an initial matter with regard to these studies, the EPA notes that the focus of the ISA is on assessing the most policy-relevant scientific evidence. In the current review, the ISA considered over 1,000 new studies that have been published since the last review. Thus, it is not surprising that, as the body of evidence has been strengthened since the last review, some of the studies considered in the last review are no longer among the most policy relevant. However, based on the information included in the 2007 Staff Paper, the EPA does not agree that the studies highlighted by commenters provide compelling support for a level below 70 ppb. In fact, as discussed in the Staff Paper in the last review (U.S. EPA, 2007, p. 6–9; Appendix 3B), the O_3 concentrations reported for these studies, and the concentrations highlighted by commenters, were based on averaging across multiple monitors in study areas. Given that the highest monitor in an area is used to determine whether that area meets or violates the NAAQS, the averaged concentrations reported in the Staff Paper are thus not appropriate for direct comparison to the level of the O_3 standard. When the Staff Paper considered the O_3 concentrations measured at individual monitors for the subset of these study areas with particularly low concentrations, they were almost universally found to be above, and in many cases well above, even the current standard level of 75 ppb.[141] Based on the above

[138] Air quality analyses in the HREA indicate that reducing the level of the primary standard from 75 ppb to 70 ppb will result in reductions in the O_3 concentrations in the upper portions of ambient distributions. This includes 8-hour ambient O_3 concentrations at, and somewhat below, 60 ppb (U.S. EPA, 2014a, Figures 4–9 and 4–10).

[139] The uncertainty associated with the potential adversity of any such effects would be even greater than that discussed above for the 60 ppb benchmark.

[140] As noted above (II.B.2.b.ii and II.B.3), the studies by Silverman and Ito (2010) and Strickland *et al.* (2010) provided support for the Administrator's decision to revise the current primary O_3 standard, but do not provide insight into the appropriateness of specific standard levels below 75 ppb.

[141] For one study conducted in Vancouver, where data from individual monitors did indicate ambient concentrations below the level of the current standard (Vedal *et al.*, 2003), the Staff Paper noted that the study authors questioned whether O_3, other gaseous pollutants, and PM in this study may be

Continued

considerations, and consistent with the Administrator's overall decision to place less emphasis on air quality in locations of epidemiologic studies to select a standard level, the EPA disagrees with commenters who asserted that epidemiologic studies included in the last review, but not cited in the ISA or PA in this review, necessitate a level below 70 ppb. In fact, the EPA notes that these studies are consistent with the majority of the U.S. studies evaluated in the PA in the current review, in that most were conducted in locations that would have violated the current O_3 NAAQS over at least part of the study periods.

iii. Exposure and Risk Assessments

Some commenters supporting levels below 70 ppb also asserted that quantitative analyses in the HREA are biased such that they understate O_3 exposures of concern and risks of O_3-induced FEV_1 decrements. Many of these comments are discussed above within the context of the adequacy of the current standard (II.B.2.b.i), including comments pointing out that exposure and risk estimates are based on information from healthy adults rather than at-risk populations; comments noting that the exposure assessment evaluates 8-hour O_3 exposures rather than the 6.6-hour exposures used in controlled human exposure studies; and comments asserting that the EPA's exposure and risk analyses rely on people staying indoors on high pollution days (*i.e.,* averting behavior).

As discussed in section II.B.2.b.i above, while the EPA agrees with certain aspects of these commenters' assertions, we do not agree with their overall conclusions. In particular, there are aspects of the HREA's quantitative analyses that, if viewed in isolation, would tend to either overstate or understate O_3 exposures and/or health risks. While commenters tended to focus on those aspects of the assessments that support their position, they tended to ignore aspects of the assessments that do not support their position (points that were often raised by commenters on the other side of the issue). Rather than viewing the potential implications of these aspects of the HREA assessments in isolation, the EPA considers them together, along with other issues and uncertainties related to the interpretation of exposure and risk estimates.

For example, some commenters who advocated for a level below 70 ppb asserted that the exposure assessment could underestimate O_3 exposures for highly active populations, including outdoor workers and children who spend a large portion of time outdoors during summer. In support of these assertions, commenters highlighted sensitivity analyses conducted in the HREA. However, as noted in the HREA (U.S. EPA, 2014a, Table 5–10), this aspect of the assessment is likely to have only a ''low to moderate'' impact on the magnitude of exposure estimates. To put this magnitude in perspective, HREA sensitivity analyses conducted in a single urban study area indicate that, regardless of whether exposure estimates for children are based on all available diaries or on a subset of diaries restricted to simulate highly exposed children, a revised standard with a level of 70 ppb is estimated to protect more than 99% of children from experiencing two or more exposures of concern at or above 70 ppb (U.S. EPA, 2014a, Chapter 5 Appendices, Figure 5G–9).[142] [143] In contrast to the focus of commenters who supported a level below 70 ppb, other aspects of quantitative assessments, some of which were highlighted by commenters who opposed revising the current standard (II.B.2), tend to result in overestimates of O_3 exposures. These aspects are characterized in the HREA as having either a ''low,'' a ''low-to-moderate,'' or a ''moderate'' impact on the magnitudes of exposure estimates.

In its reviews of the HREA and PA, CASAC recognized many of the uncertainties and issues highlighted by commenters. Even considering these uncertainties, CASAC endorsed the approaches adopted by the EPA to assess O_3 exposures and health risks, and CASAC used exposure and risk estimates as part of the basis for their recommendations on the primary O_3 NAAQS (Frey, 2014c). Thus, as discussed in section II.B.2.b.i above, the EPA disagrees with commenters who claim that the aspects of the quantitative assessments that they highlight lead to overall underestimates of exposures or health risks.[144]

Some commenters further contended that the level of the primary O_3 standard should be set below 70 ppb in order to compensate for the use of a form that allows multiple days with concentrations higher than the standard level. These groups submitted air quality analyses to support their point that the current fourth-high form allows multiple days per year with ambient O_3 concentrations above the level of the standard. While the EPA does not dispute the air quality analyses submitted by these commenters, and agrees that fourth-high form allows multiple days per year with ambient O_3 concentrations above the level of the standard (3 days per year, on average over a 3-year period), the Agency disagrees with commenters' assertion that, because of this, the level of the primary O_3 standard should be set below 70 ppb. As discussed above (II.A.2), the quantitative assessments that informed the Administrator's proposed decision, presented in the HREA and considered in the PA and by CASAC, estimated O_3 exposures and health risks associated with air quality that ''just meets'' various standards with the current 8-hour averaging time and fourth-high, 3-year average form. Thus, in considering the degree of public health protection appropriate for the primary O_3 standard, the Administrator has considered quantitative exposure and risk estimates that are based a fourth-high form, and therefore on a standard that, as these commenters point out, allows multiple days per year with ambient O_3 concentrations above the level of the standard.

iv. CASAC Advice

Many commenters, including those representing major medical, public health, or environmental groups; some state agencies; and a large number of individual commenters, focused on CASAC advice in their rationale supporting levels below 70 ppb, and as low as 60 ppb. These commenters generally asserted that the EPA must

acting as surrogate markers of pollutant mixes that contain more toxic compounds, ''since the low measured concentrations were unlikely, in their opinion, to cause the observed effects'' (U.S. EPA, 2007, p. 6–16). The Staff Paper further noted that another study conducted in Vancouver failed to find statistically significant associations with O_3 (Villeneuve *et al.*, 2003).

[142] More specifically, based on all children's diaries, just under 0.1% of children are estimated to experience two or more exposures of concern at or above 70 ppb. Based on simulated profiles of highly exposed children, this estimate increased to just over 0.1% (U.S. EPA, 2014a, Chapter 5 Appendices, Figure 5G–9).

[143] In addition, when diaries were selected to mimic exposures that could be experienced by outdoor workers, the percentages of modeled individuals estimated to experience exposures of concern were generally similar to the percentages estimated for children (*i.e.,* using the full database of diary profiles) in the worst-case cities and years (*i.e.,* cities and years with the highest exposure estimates) (U.S. EPA, 2014, section 5.4.3.2, Figure 5–14).

[144] As discussed in II.B.2.b above, in weighing the various uncertainties, which can bias exposure results in different directions but tend to have impacts that are similar in magnitude (U.S. EPA, 2014a, Table 5–10), and in light of CASAC's advice based on its review of the HREA and the PA, the EPA continues to conclude that the approach to considering estimated exposures of concern in the HREA, PA, and the proposal reflects an appropriate balance, and provides an appropriate basis for considering the public health protectiveness of the primary O_3 standard.

give deference to CASAC. In some cases, these commenters expressed strong objections to a level of 70 ppb, noting CASAC policy advice that such a level would provide little margin of safety.

The EPA agrees that CASAC advice is an important consideration in reaching a decision on the standard level (see *e.g.* CAA section 307 (d)(3)),[145] though not with commenters' conclusion that CASAC advice necessitates a standard level below 70 ppb. As discussed above (II.C.4.a), the Administrator carefully considered CASAC advice in the proposal, and she judged that her proposed decision to revise the level to within the range of 65 to 70 ppb was consistent with CASAC advice, based on the available science.

As in the proposal, in her final decision on level the Administrator notes CASAC's overall conclusion that ''based on the scientific evidence from clinical studies, epidemiologic studies, animal toxicology studies, as summarized in the ISA, the findings from the exposure and risk assessments as summarized in the HREA, and the interpretation of the implications of all of these sources of information as given in the Second Draft PA . . . there is adequate scientific evidence to recommend a range of levels for a revised primary ozone standard from 70 ppb to 60 ppb'' (Frey, 2014c, p. 8). Thus, CASAC used the health evidence and exposure/risk information to inform its range of recommended standard levels, a range that included an upper bound of 70 ppb based on the scientific evidence, and it did not use the evidence and information to recommend setting the primary O_3 standard at any specific level within the range of 70 to 60 ppb. In addition, CASAC further stated that ''the choice of a level within the range recommended based on scientific evidence [*i.e.,* 70 to 60 ppb] is a policy judgment under the statutory mandate of the Clean Air Act'' (Frey, 2014c, p. ii).

In addition to its advice based on the scientific evidence, CASAC offered the ''policy advice'' to set the level below 70 ppb, stating that a standard level of 70 ppb ''may not meet the statutory requirement to protect public health with an adequate margin of safety'' (Frey, 2014c, p. ii). In supporting its policy advice to set the level below 70 ppb, CASAC noted the respiratory effects that have been shown to occur in controlled human exposure studies following exposures from 60 to 80 ppb O_3, and the extent to which various standard levels are estimated to allow the occurrence of population exposures that can result in such effects (Frey, 2014c, pp. 7–8).

The EPA agrees that an important consideration when reaching a decision on level is the extent to which a revised standard is estimated to allow the types of exposures shown in controlled human exposure studies to cause respiratory effects. In reaching her final decision that a level of 70 ppb is requisite to protect public health with an adequate margin of safety (II.C.4.c, below), the Administrator carefully considers the potential for such exposures and effects. In doing so, she emphasizes the importance of setting a standard that limits the occurrence of the exposures about which she is most concerned (*i.e.,* those for which she has the most confidence in the adversity of the resulting effects, which are repeated exposures of concern at or above 70 or 80 ppb, as discussed above in II.C.4.b.i). Based on her consideration of information from controlled human exposure studies in light of CASAC advice and ATS recommendations, the Administrator additionally judges that there is important uncertainty in the extent to which the effects shown to occur following exposures to 60 ppb O_3 are adverse to public health (discussed above, II.C.4.b.i and II.C.4.b.iii). However, based on the effects that have been shown to occur, CASAC advice indicating the importance of considering these effects, and ATS recommendations indicating the potential for adverse population-level effects (II.C.4.b.i, II.C.4.b.iii), she concludes that it is appropriate to give some consideration to the extent to which a revised standard could allow the respiratory effects that have been observed following exposures to 60 ppb O_3.

When considering the extent to which a revised standard could allow O_3 exposures that have been shown in controlled human exposures studies to result in respiratory effects, the Administrator is most concerned about protecting the public, including at-risk populations, against repeated occurrences of such exposures of concern (II.C.4.b.i, above). In considering the appropriate metric for evaluating repeated occurrences of exposures of concern, the Administrator acknowledges that it is not clear from the evidence, or from the ATS recommendations, CASAC advice, or public comments, how particular numbers of exposures of concern could impact the seriousness of the resulting effects, especially at lower exposure concentrations. Therefore, the Administrator judges that focusing on HREA estimates of two or more exposures of concern provides a health-protective approach to considering the potential for repeated occurrences of exposures of concern that could result in adverse effects. She notes that other possible metrics for considering repeated occurrences of exposures of concern (*e.g.,* 3 or more, 4 or more, etc.) would result in smaller exposure estimates.

As discussed further below (II.C.4.c), the Administrator notes that a revised standard with a level of 70 ppb is estimated to eliminate the occurrence of two or more exposures of concern to O_3 concentrations at or above 80 ppb and to virtually eliminate the occurrence of two or more exposures of concern to O_3 concentrations at or above 70 ppb (Table 1, above). For the 70 ppb benchmark, this reflects about a 90% reduction in the number of children estimated to experience two or more exposures of concern, compared to the current standard.[146] Even considering the worst-case urban study area and worst-case year evaluated in the HREA, a standard with a level of 70 ppb is estimated to protect more than 99% of children from experiencing two or more exposures of concern to O_3 concentrations at or above 70 ppb (Table 1).

Though the Administrator judges that there is greater uncertainty with regard to the occurrence of adverse effects following exposures as low as 60 ppb, she notes that a revised standard with a level of 70 ppb is estimated to protect the vast majority of children in urban study areas (*i.e.,* about 96% to more than 99% in individual areas) from experiencing two or more exposures of concern at or above 60 ppb. Compared to the current standard, this represents a reduction of more than 60% in exposures of concern for the 60 ppb benchmark (Table 1). Given the Administrator's uncertainty regarding the adversity of the effects following exposures to 60 ppb O_3, and her health-protective approach to considering repeated occurrences of exposures of concern, the Administrator judges that this degree of protection is appropriate and that it reflects substantial protection against the occurrence of O_3-induced effects, including effects for which she judges the adversity to public health is uncertain.

[145] The EPA notes, of course, that the CAA places the responsibility for judging what standard is requisite with the Administrator and only requires that, if her decision differs in important ways from CASAC's advice, she explain her reasoning for differing.

[146] Percent reductions in this section refer to reductions in the number of children in HREA urban study areas (averaged over the years evaluated in the HREA) estimated to experience exposures of concern, based on the information in Table 1 above.

While being less concerned about single occurrences of exposures of concern, especially at lower exposure concentrations, the Administrator also notes that a standard with a level of 70 ppb is estimated to (1) virtually eliminate all occurrences of exposures of concern at or above 80 ppb; (2) protect ≥ about 99% of children in urban study areas from experiencing any exposures of concern at or above 70 ppb; and (3) to achieve substantial reductions (*i.e.,* about 50%), compared to the current standard, in the occurrence of one or more exposures of concern at or above 60 ppb (Table 1).

Given the information and advice noted above (and in II.C.4.b.i, II.C.4.b.iii), the Administrator judges that a revised standard with a level of 70 ppb will effectively limit the occurrence of the O_3 exposures for which she has the most confidence in the adversity of the resulting effects (*i.e.,* based on estimates for the 70 and 80 ppb benchmarks). She further judges that such a standard will provide a large degree of protection against O_3 exposures for which there is greater uncertainty in the adversity of effects (*i.e.,* those observed following exposures to 60 ppb O_3), contributing to the margin of safety of the standard. See M*ississippi,* 744 F. 3d at 1353 (''By requiring an 'adequate margin of safety', Congress was directing EPA to build a buffer to protect against uncertain and unknown dangers to human health''). Given the considerable protection provided against repeated exposures of concern for all of the benchmarks evaluated, including the 60 ppb benchmark, the Administrator judges that a standard with a level of 70 ppb will provide an adequate margin of safety against the adverse O_3-induced effects shown to occur following exposures at or above 72 ppb, and judged by CASAC likely to occur following exposures somewhat below 72 ppb.[147]

Contrary to the conclusions of commenters who advocated for a level below 70 ppb, the Administrator notes that her final decision is consistent with CASAC's advice, based on the scientific evidence, and with CASAC's focus on setting a revised standard to further limit the occurrence of the respiratory effects observed in controlled human exposure studies, including effects observed following exposures to 60 ppb O_3. Given her judgments and conclusions discussed above, and given that the CAA reserves the choice of the standard that is requisite to protect public health with an adequate margin of safety for the judgment of the EPA Administrator, she disagrees with commenters who asserted that CASAC advice necessitates a level below 70 ppb, and as low as 60 ppb. The Administrator's final conclusions on level are discussed in more detail below (II.C.4.c).

[147] As discussed above (II.C.4.b.i), when commenting on the extent to which the study by Schelegle *et al.* (2009) suggests the potential for adverse effects following O_3 exposures below 72 ppb, CASAC stated the following: ''[I]f subjects had been exposed to ozone using the 8-hour averaging period used in the standard [rather than the 6.6-hour exposures evaluated in the study], adverse effects could have occurred at lower concentration. Further, in our judgment, the level at which adverse effects might be observed would likely be lower for more sensitive subgroups, such as those with asthma'' (Frey, 2014c, p. 5).

c. Administrator's Final Decision Regarding Level

Having carefully considered the public comments on the appropriate level of the primary O_3 standard, as discussed above and in the Response to Comments document, the Administrator believes her scientific and policy judgments in the proposal remain valid. In conjunction with her decisions to retain the current indicator, averaging time, and form (II.C.1 to II.C.3, above), the Administrator is revising the level of the primary O_3 standard to 70 ppb. In doing so, she is selecting a primary O_3 standard that is requisite to protect public health with an adequate margin of safety, in light of her judgments based on an interpretation of the scientific evidence and exposure/risk information that neither overstates nor understates the strengths and limitations of that evidence and information and the appropriate inferences to be drawn therefrom.

The Administrator's decision to revise the level of the primary O_3 standard to 70 ppb builds upon her conclusion that the overall body of scientific evidence and exposure/risk information calls into question the adequacy of public health protection afforded by the current standard, particularly for at-risk populations and lifestages (II.B.3).[148] Consistent with the proposal, her decision on level places the greatest emphasis on the results of controlled human exposure studies and on quantitative analyses based on information from these studies, particularly analyses of O_3 exposures of concern. As in the proposal, and as discussed further below, she views the results of the lung function risk assessment, analyses of O_3 air quality in locations of epidemiologic studies, and epidemiology-based quantitative health risk assessments as providing information in support of her decision to revise the current standard, but a more limited basis for selecting a particular standard level among a range of options. See *Mississippi,* 744 F. 3d at 1351–52 (studies can legitimately support a decision to revise the standard, but not provide sufficient information to justify their use in setting the level of a revised standard).

[148] At-risk populations include people with asthma; children and older adults; people who are active outdoors, including outdoor workers; people with certain genetic variants; and people with reduced intake of certain nutrients.

Given her consideration of the evidence, exposure/risk information, advice from CASAC, and public comments, the Administrator judges that a standard with a level of 70 ppb is requisite to protect public health with an adequate margin of safety. She notes that the determination of what constitutes an adequate margin of safety is expressly left to the judgment of the EPA Administrator. See *Lead Industries Association* v. *EPA,* 647 F.2d at 1161–62; *Mississippi,* 744 F. 3d at 1353. She further notes that in evaluating how particular standards address the requirement to provide an adequate margin of safety, it is appropriate to consider such factors as the nature and severity of the health effects, the size of sensitive population(s) at risk, and the kind and degree of the uncertainties present (I.B, above). Consistent with past practice and long-standing judicial precedent, the Administrator takes the need for an adequate margin of safety into account as an integral part of her decision-making on the appropriate level, averaging time, form, and indicator of the standard.[149]

In considering the need for an adequate margin of safety, the Administrator notes that a standard with a level of 70 ppb O_3 would be expected to provide substantial improvements in public health, including for at-risk groups such as children and people with asthma. The following paragraphs summarize the basis for the Administrator's conclusion that a revised primary O_3 standard with a level of 70 ppb is requisite to protect the public health with an adequate margin of safety.

As an initial matter, consistent with her conclusions on the need for revision of the current standard (II.B.3), in reaching a decision on level the Administrator places the most weight on information from controlled human exposure studies. In doing so, she notes that controlled human exposure studies provide the most certain evidence indicating the occurrence of health

[149] See, *e.g. NRDC* v. *EPA,* 902 F. 2d 962, 973–74 (D.C. Cir. 1990).

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effects in humans following specific O_3 exposures. In particular, she notes that the effects reported in controlled human exposure studies are due solely to O_3 exposures, and interpretation of study results is not complicated by the presence of co-occurring pollutants or pollutant mixtures (as is the case in epidemiologic studies). The Administrator also observes that her emphasis on information from controlled human exposure studies is consistent with CASAC's advice and interpretation of the scientific evidence (Frey, 2014c).

With regard to the effects shown in controlled human exposure studies following specific O_3 exposures, as discussed in more detail above (II.B, II.C.4.b.i), the Administrator notes that (1) the largest respiratory effects, and the broadest range of effects, have been studied and reported following exposures to 80 ppb O_3 or higher (*i.e.,* decreased lung function, increased airway inflammation, increased respiratory symptoms, AHR, and decreased lung host defense); (2) exposures to O_3 concentrations as low as 72 ppb have been shown to both decrease lung function and result in respiratory symptoms; and (3) exposures to O_3 concentrations as low as 60 ppb have been shown to decrease lung function and to increase airway inflammation.

While such controlled human exposure studies provide a high degree of confidence regarding the occurrence of health effects following exposures to O_3 concentrations from 60 to 80 ppb, there are no universally accepted criteria by which to judge the adversity of the observed effects. To inform her judgments on the potential adversity to public health of effects reported in controlled human exposure studies, the Administrator considers ATS recommendations and CASAC advice, as described in detail above (II.B.2, II.C.4.b.i, II.C.4.b.iii, II.C.4.b.iv). Based on her consideration of such recommendations and advice, the Administrator is confident that the respiratory effects that have been observed following exposures to 72 ppb O_3 or above can be adverse. In addition, she judges that adverse effects are likely to occur following exposures somewhat below 72 ppb (II.C.4.b.i). However, as described above (II.C.4.b.i, II.C.4.b.iii, II.C.4.b.iv), the Administrator is notably less confident in the adversity to public health of the respiratory effects that have been observed following exposures to O_3 concentrations as low as 60 ppb, given her consideration of the following: (1) ATS recommendations indicating uncertainty in judging adversity based on lung function decrements alone; (2) uncertainty in the extent to which a short-term, transient population-level decrease in FEV_1 would increase the risk of other, more serious respiratory effects in that population (*i.e.,* per ATS recommendations on population-level risk); and (3) compared to 72 ppb, CASAC advice is less clear regarding the potential adversity of effects at 60 ppb.

Taken together, the Administrator concludes that the evidence from controlled human exposure studies provides strong support for her conclusion that a revised standard with a level of 70 ppb is requisite to protect the public health with an adequate margin of safety. She bases this conclusion, in part, on the fact that such a standard level would be well below the O_3 exposure concentration shown to result in the widest range of respiratory effects (*i.e.,* 80 ppb), and below the lowest O_3 exposure concentration shown to result in the adverse combination of lung function decrements and respiratory symptoms (*i.e.,* 72 ppb). See *Lead Industries,* 647 F. 2d at 1160 (setting NAAQS at level well below the level where the clearest adverse effects occur, and at a level eliminating most ''sub-clinical effects'' provides an adequate margin of safety).

As discussed above (II.C.4.b.i), the Administrator also notes that a revised O_3 standard with a level of 70 ppb can provide substantial protection against the broader range of O_3 exposure concentrations that have been shown in controlled human exposure studies to result in respiratory effects, including exposure concentrations below 70 ppb. The degree of protection provided by any NAAQS is due to the combination of all of the elements of the standard (*i.e.,* indicator, averaging time, form, level) and, in the case of the fourth-high form of the revised primary O_3 standard (II.C.3), the large majority of days in areas that meet the revised standard will have 8-hour O_3 concentrations below 70 ppb, with most days having 8-hour O_3 concentrations well below this level. In addition, the degree of protection provided by the O_3 NAAQS is also dependent on the extent to which people experience health-relevant O_3 exposures in locations meeting the NAAQS. As discussed above, for a pollutant like O_3 where adverse responses are critically dependent on ventilation rates, the Administrator notes that it is important to consider activity patterns in the exposed population. Not considering activity patterns, and corresponding ventilation rates, can result in a standard that provides more protection than is requisite. Therefore, as discussed in the proposal, in considering the degree of protection provided by a revised primary O_3 standard, the Administrator considers the extent to which that standard would be expected to limit population exposures of concern (*i.e.,* which take into account activity patterns and estimated ventilation rates) to the broader range of O_3 exposure concentrations shown to result in health effects.

Due to interindividual variability in responsiveness, the Administrator notes that not every occurrence of an exposure of concern will result in an adverse effect (II.C.4.b.i). Moreover, repeated occurrences of some of the effects demonstrated following exposures of concern could increase the likelihood of adversity (U.S. EPA, 2013, Section 6.2.3, p. 6–76). In particular, she notes that the types of respiratory effects that can occur following exposures of concern, particularly if experienced repeatedly, provide a plausible mode of action by which O_3 may cause other more serious effects. Therefore, as in the proposal, the Administrator is most concerned about protecting at-risk populations against repeated occurrences of exposures of concern. In considering the appropriate metric for evaluating repeated occurrences of exposures of concern, the Administrator acknowledges that it is not clear from the evidence, or from the ATS recommendations, CASAC advice, or public comments, how particular numbers of exposures of concern could impact the seriousness of the resulting effects, especially at lower exposure concentrations. Therefore, the Administrator judges that focusing on HREA estimates of two or more exposures of concern provides a health-protective approach to considering the potential for repeated occurrences of exposures of concern that could result in adverse effects.

Based on her consideration of adversity discussed above, the Administrator places the most emphasis on setting a standard that appropriately limits repeated occurrences of exposures of concern at or above the 70 and 80 ppb benchmarks. She notes that a revised standard with a level of 70 ppb is estimated to eliminate the occurrence of two or more exposures of concern to O_3 concentrations at or above 80 ppb and to virtually eliminate the occurrence of two or more exposures of concern to O_3 concentrations at or above 70 ppb for all children and children with asthma, even in the worst-case year and location evaluated.

While she is less confident that adverse effects will occur following exposures to O_3 concentrations as low as 60 ppb, as discussed above, the

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Administrator judges that it is also appropriate to consider estimates of exposures of concern for the 60 ppb benchmark. Consistent with this judgment, although CASAC advice regarding the potential adversity of effects at 60 ppb was less definitive than for effects at 72 ppb, CASAC did clearly advise the EPA to consider the extent to which a revised standard is estimated to limit the effects observed following 60 ppb exposures (Frey, 2014c). Therefore, the Administrator considers estimated exposures of concern for the 60 ppb benchmark, particularly considering the extent to which the health protection provided by a revised standard includes a margin of safety against the occurrence of adverse O_3-induced effects. The Administrator notes that a revised standard with a level of 70 ppb is estimated to protect the vast majority of children in urban study areas (*i.e.,* about 96% to more than 99% of children in individual areas) from experiencing two or more exposures of concern at or above 60 ppb. Compared to the current standard, this represents a reduction of more than 60%.

Given the considerable protection provided against repeated exposures of concern for all of the benchmarks evaluated, including the 60 ppb benchmark, the Administrator judges that a standard with a level of 70 ppb will incorporate a margin of safety against the adverse O_3-induced effects shown to occur following exposures at or above 72 ppb, and judged likely to occur following exposures somewhat below 72 ppb.

While the Administrator is less concerned about single occurrences of O_3 exposures of concern, especially for the 60 ppb benchmark, she judges that estimates of one or more exposures of concern can provide further insight into the margin of safety provided by a revised standard. In this regard, she notes that a standard with a level of 70 ppb is estimated to (1) virtually eliminate all occurrences of exposures of concern at or above 80 ppb; (2) protect the vast majority of children in urban study areas from experiencing any exposures of concern at or above 70 ppb (*i.e.,* ≥ about 99%, based on mean estimates; Table 1); and (3) to achieve substantial reductions, compared to the current standard, in the occurrence of one or more exposures of concern at or above 60 ppb (*i.e.,* about a 50% reduction; Table 1). The Administrator judges that these results provide further support for her conclusion that a standard with a level of 70 ppb will incorporate an adequate margin of safety against the occurrence of O_3 exposures that can result in effects that are adverse to public health.

The Administrator additionally judges that a standard with a level of 70 ppb would be expected to result in important reductions, compared to the current standard, in the population-level risk of O_3-induced lung function decrements (≥10%, ≥15%) in children, including children with asthma. Specifically, a revised standard with a level of 70 ppb is estimated to reduce the risk of two or more O_3-induced decrements by about 30% and 20% for decrements ≥15 and 10%, respectively (Table 2, above). However, as discussed above (II.C.4.b.i), the Administrator judges that there are important uncertainties in using lung function risk estimates as a basis for considering the occurrence of adverse effects in the population given (1) the ATS recommendation that ''a small, transient loss of lung function, by itself, should not automatically be designated as adverse'' (ATS, 2000a); (2) uncertainty in the extent to which a transient population-level decrease in FEV_1 would increase the risk of other, more serious respiratory effects in that population (*i.e.,* per ATS recommendations on population-level risk); and (3) that CASAC did not advise considering a standard that would be estimated to eliminate O_3-induced lung function decrements ≥10 or 15% (Frey, 2014c). Moreover, as at proposal, the Administrator notes that the variability in lung function risk estimates across urban study areas is often greater than the differences in risk estimates between various standard levels (Table 2, above).[150] Given this, and the resulting considerable overlap between the ranges of lung function risk estimates for different standard levels, the Administrator puts limited weight on the lung function risk estimates for distinguishing between the degrees of public health protection provided by alternative standard levels. Therefore, the Administrator judges that while a standard with a level of 70 ppb would be expected to result in important reductions, compared to the current standard, in the population-level risk of O_3-induced lung function decrements (>10%, 15%) in children, including children with asthma, she also judges that estimated risks of O_3-induced lung function decrements provide a more limited basis than exposures of concern for distinguishing between the appropriateness of the health protection afforded by a standard level of 70 ppb versus lower levels.

The Administrator also considers the epidemiologic evidence and the quantitative risk estimates based on information from epidemiologic studies. As discussed in the proposal, and above in the EPA's responses to significant comments, although the Administrator acknowledges the important uncertainties in using the O_3 epidemiologic studies as a basis for selecting a standard level, she notes that these studies can provide perspective on the degree to which O_3-associated health effects have been identified in areas with air quality likely to have met various standards. Specifically, the Administrator notes analyses in the PA (U.S. EPA, 2014c, section 4.4.1) indicating that a revised standard with a level of 70 ppb would be expected to require additional reductions, beyond those required by the current standard, in the short- and long-term ambient O_3 concentrations that provided the basis for statistically significant O_3 health effect associations in both the single-city and multicity epidemiologic studies evaluated. As discussed above in the response to comments, while the Administrator concludes that these analyses support a level at least as low as 70 ppb, based on a study reporting health effect associations in a location that met the current standard over the entire study period but that would have violated a revised standard with a level of 70 ppb,[151] she further judges that they are of more limited utility for distinguishing between the appropriateness of the health protection estimated for a standard level of 70 ppb and the protection estimated for lower levels. Thus, the Administrator notes that a revised standard with a level of 70 ppb will provide additional public health protection, beyond that provided by the current standard, against the clearly adverse effects reported in

[150] For example, the average percentage of children estimated to experience two or more decrements ≥10% ranges from approximately 6 to 11% for a standard level of 70 ppb, up to about 9% for a level of 65 ppb, and up to about 6% for a level of 60 ppb (Table 2, above).

[151] As discussed above (II.B.2.c.ii and II.B.3), the study by Mar and Koenig (2009) reported positive and statistically significant associations with respiratory emergency department visits in a location that would have met the current standard over the entire study period, but violated a standard with a level of 70 ppb. In addition, air quality analyses in the locations of two additional studies highlighted in sections II.B.2 and II.B.3 (Silverman and Ito, 2010; Strickland *et al.,* 2010) were used in the PA to inform staff conclusions on the adequacy of the current primary O_3 standard. However, they did not provide insight into the appropriateness of standard levels below 75 ppb and, therefore, these analyses were not used to inform conclusions on potential alternative standard levels lower than 75 ppb (U.S. EPA, 2014c, Chapters 3 and 4). See *Mississippi,* 744 F. 3d at 1352–53 (study appropriate for determining causation may not be probative for determining level of a revised standard).

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epidemiologic studies. She judges that a standard with a level of 70 ppb strikes an appropriate balance between setting the level to require reductions in the ambient O_3 concentrations associated with statistically significant health effects in epidemiologic studies, while not being more protective than necessary in light of her considerable uncertainty in the extent to which studies clearly show O_3-attributable effects at lower ambient O_3 concentrations. This judgment is consistent with the Administrator's conclusions based on information from controlled human exposure studies, as discussed above.

With regard to epidemiology-based risk estimates, the Administrator takes note of the CASAC conclusion that ''[a]lthough the estimates for short-term exposure impacts are subject to uncertainty, the data supports a conclusion that there are meaningful reductions in mean premature mortality associated with ozone levels lower than the current standard'' (Frey, 2014a, p. 10). While she concludes that epidemiology-based risk analyses provide only limited support for any specific standard level, consistent with CASAC advice the Administrator judges that, compared to the current standard, a revised standard with a level of 70 ppb will result in meaningful reductions in the mortality and respiratory morbidity risk that is associated with short-or long-term ambient O_3 concentrations.

Given all of the evidence and information discussed above, the Administrator judges that a standard with a level of 70 ppb is requisite to protect public health with an adequate margin of safety, and that a level below 70 ppb would be more than ''requisite'' to protect the public health. In reaching this conclusion, she notes that a decision to set a lower level would place a large amount of emphasis on the potential public health importance of (1) further reducing the occurrence of O_3 exposures of concern, though the exposures about which she is most concerned are estimated to be almost eliminated with a level of 70 ppb, and lower levels would be expected to achieve virtually no additional reductions in these exposures (see Table 1, above); (2) further reducing the risk of O_3-induced lung function decrements >10 and 15%, despite having less confidence in judging the potential adversity of lung function decrements alone and the considerable overlap between risk estimates for various standard levels that make it difficult to distinguish between the risk reductions achieved; (3) further reducing ambient O_3 concentrations, relative to those in locations of epidemiologic studies, though associations have not been reported for air quality that would have met a standard with a level of 70 ppb across all study locations and over entire study periods, and despite her consequent judgment that air quality analyses in epidemiologic study locations are not informative regarding the additional degree of public health protection that would be afforded by a standard set at a level below 70 ppb; and (4) further reducing epidemiology-based risk estimates, despite the important uncertainties in those estimates. As discussed in this section and in the responses to significant comments above, the Administrator does not agree that it is appropriate to place significant weight on these factors or to use them to support the appropriateness of standard levels below 70 ppb O_3. Compared to an O_3 standard level of 70 ppb, the Administrator concludes that the extent to which lower standard levels could result in further public health improvements becomes notably less certain.

Thus, having carefully considered the evidence, information, CASAC advice, and public comments relevant to her decision on the level of the primary O_3 standard, as discussed above and in the Response to Comments document, the Administrator is revising the level of the primary O_3 standard to 70 ppb. She is mindful that the selection of a primary O_3 standard that is requisite to protect public health with an adequate margin of safety requires judgments based on an interpretation of the scientific evidence and exposure/risk information that neither overstate nor understate the strengths and limitations of that evidence and information and the appropriate inferences to be drawn therefrom. Her decision places the greatest emphasis on the results of controlled human exposure studies and on quantitative analyses based on information from these studies, particularly analyses of O_3 exposures of concern. As in the proposal, and as discussed above, she views the results of the lung function risk assessment, analyses of O_3 air quality in locations of epidemiologic studies, and epidemiology-based quantitative health risk assessments as providing information in support of her decision to revise the current standard, but a more limited basis for selecting a particular standard level among a range of options.

In making her decision to revise the level of the primary O_3 standard to 70 ppb, the Administrator judges that a revised standard with a level of 70 ppb strikes the appropriate balance between limiting the O_3 exposures about which she is most concerned and not going beyond what would be required to effectively limit such exposures. Specifically, the Administrator judges it appropriate to set a standard estimated to eliminate, or almost eliminate, repeated occurrences of exposures of concern for the 70 and 80 ppb benchmarks. She further judges that a lower standard level would not be appropriate given that lower levels would be expected to achieve virtually no additional reductions in repeated occurrences of exposures of concern for these benchmarks. For the 60 ppb benchmark, a level of 70 ppb is estimated to protect the vast majority of children (including children with asthma) in urban study areas from experiencing two or more exposures of concern, reflecting important reductions in such exposures compared to the current standard and indicating that the revised primary O_3 standard provides an adequate margin of safety. Given these results, including the considerable protection provided against repeated exposures of concern for the 60 ppb benchmark, the Administrator judges that a standard with a level of 70 ppb incorporates an adequate margin of safety against the occurrence of adverse O_3-induced effects.

For all of the above reasons, the Administrator concludes that a primary O_3 standard with an 8-hour averaging time; a 3-year average, fourth-high form; and a level of 70 ppb is requisite to protect public health, including the health of at-risk populations, with an adequate margin of safety. Therefore, in this final rule she is setting the level of the primary O_3 standard at 70 ppb.

D. Decision on the Primary Standard

For the reasons discussed above, and taking into account information and assessments presented in the ISA, HREA, and PA, the advice and recommendations of the CASAC Panel, and the public comments, the Administrator has decided to revise the existing 8-hour primary O_3 standard. Specifically, the Administrator is revising the level of the primary O_3 standard to 70 ppb. The revised 8-hour primary standard, with a level of 70 ppb, would be met at an ambient air monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration is less than or equal to 70 ppb. Data handling conventions are specified in the new Appendix U that is adopted, as discussed in section V below.

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At this time, EPA is also promulgating revisions to the Air Quality Index (AQI) for O_3 to be consistent with the revisions to the primary O_3 standard and the health information evaluated in this review of the standards. These revisions are discussed below in section III.

III. Communication of Public Health Information

Information on the public health implications of ambient concentrations of criteria pollutants is currently made available primarily through EPA's AQI program. The AQI has been in use since its inception in 1999 (64 FR 42530). It provides accurate, timely, and easily understandable information about daily levels of pollution. It is designed to tell individual members of the public how clean or unhealthy their air is, whether health effects might be a concern, and, if so, measures individuals can take to reduce their exposure to air pollution.[152] See CAA section 127. The AQI focuses on health effects individuals may experience within a few hours or days after breathing unhealthy air. The AQI establishes a nationally uniform system of indexing pollution concentrations for O_3, CO, NO_2, PM and SO_2. The AQI converts pollutant concentrations in a community's air to a number on a scale from 0 to 500. Reported AQI values enable the public to know whether air pollution concentrations in a particular location are characterized as good (0–50), moderate (51–100), unhealthy for sensitive groups (101–150), unhealthy (151–200), very unhealthy (201–300), or hazardous (301–500). The AQI index value of 100 typically corresponds to the level of the short-term NAAQS for each pollutant. For the 2008 O_3 NAAQS, an 8-hour average concentration of 75 ppb corresponds to an AQI value of 100. An AQI value greater than 100 means that a pollutant is in one of the unhealthy categories (*i.e.,* unhealthy for sensitive groups, unhealthy, very unhealthy, or hazardous) on a given day; an AQI value at or below 100 means that a pollutant concentration is in one of the satisfactory categories (*i.e.,* moderate or good). An additional consideration in selecting breakpoints is for each category to span at least a 15 ppb range to allow for more accurate air pollution forecasting. Decisions about the pollutant concentrations at which to set the various AQI breakpoints, that delineate the various AQI categories, draw directly from the underlying health information that supports the NAAQS review.

A. Proposed Revisions to the AQI

Recognizing the importance of revising the AQI in a timely manner to be consistent with any revisions to the NAAQS, EPA proposed conforming changes to the AQI, in connection with the Agency's proposed decision on revisions to the O_3 NAAQS. These conforming changes included setting the 100 level of the AQI at the same level as the revised primary O_3 NAAQS and also making adjustments based on health information from this NAAQS review to AQI breakpoints at the lower end of each range (*i.e.,* AQI values of 50, 150, 200 and 300). The EPA did not propose to change the level at the top of the index (*i.e.,* AQI value of 500) that typically is set equal to the Significant Harm Level (40 CFR 51.16), which would apply to state contingency plans.

The EPA proposed to revise the AQI for O_3 by setting an AQI value of 100 equal to the level of the revised O_3 standard (65–70 ppb). The EPA also proposed to revise the following breakpoints: an AQI value of 50 to within a range from 49–54 ppb; an AQI value of 150 to 85 ppb; an AQI value of 200 to 105 ppb, and an AQI value of 300 to 200 ppb. All these levels are averaged over 8 hours. The EPA proposed to set an AQI value of 50, the breakpoint between the good and moderate categories, at 15 ppb below the value of the proposed standard, *i.e.,* to within a range from 49 to 54 ppb. The EPA took comment on what level within this range to select, recognizing that there is no health message for either at-risk or healthy populations in the good category. Thus, the level selected should be below the lowest concentration (*i.e.,* 60 ppb) that has been shown in controlled human exposure studies of young, healthy adults exposed to O_3 while engaged in quasi-continuous moderate exercise for 6.6 hours to cause moderate lung function decrements (*i.e.,* FEV_1 decrements ≥ 10%, which could be adverse to people with lung disease) and airway inflammation.[153] The EPA proposed to set an AQI value of 150, the breakpoint between the unhealthy for sensitive groups and unhealthy categories, at 85 ppb. At this level, controlled human exposure studies of young, healthy adults indicate that up to 25% of exposed people are likely to have moderate lung function decrements (*i.e.,* 25% have FEV_1 decrements ≥ 10%; 12% have FEV_1 decrements ≥ 15%) and up to 7% are likely to have large lung function decrements (*i.e.,* FEV_1 decrements ≥ 20%) (McDonnell *et al.*, 2012; Figure 7). Large lung function decrements would likely interfere with normal activity for many healthy people. For most people with lung disease, large lung function decrements would not only interfere with normal activity but would increase the likelihood that they would seek medical treatment (72 FR 37850, July 11, 2007). The EPA proposed to set an AQI value of 200, the breakpoint between the unhealthy and very unhealthy categories, at 105 ppb. At this level, controlled human exposure studies of young, healthy adults indicate that up to 38% of exposed people are likely to have moderate lung function decrements (*i.e.,* 38% have FEV_1 decrements ≥ 10%; 22% have FEV_1 decrements ≥ 15%) and up to 13% are likely to have large lung function decrements (*i.e.,* FEV_1 decrements ≥ 20%). The EPA proposed to set an AQI value of 300, the breakpoint between the very unhealthy and hazardous categories, at 200 ppb. At this level, controlled human exposure studies of healthy adults indicate that up to 25% of exposed individuals are likely to have large lung function decrements (*i.e.,* FEV_1 decrements ≥ 20%), which would interfere with daily activities for many of them and likely cause people with lung disease to seek medical attention.

EPA stated that the proposed breakpoints reflect an appropriate balance between reflecting the health evidence that is the basis for the proposed primary O_3 standard and providing category ranges that are large enough to be forecasted accurately, so

[152] EPA issued the AQI in 1999, updating the previous Pollutant Standards Index (PSI) to send ''a clear and consistent message to the public by providing nationally uniform information on air quality.'' The rule requires metropolitan areas of 350,000 and larger to report the AQI [and associated health effects] daily; all other AQI-related activities—including real-time ozone and particle pollution reporting, next-day air quality forecasting and action days—are voluntary and are carried out at the discretion of state, local and tribal air agencies. In the 1999 rule, we acknowledged these other programs, noting, for example, that while states primarily use the AQI ''to provide general information to the public about air quality and its relationship to public health,'' some state, local or tribal agencies use the index to call ''action days.'' Action days encourage additional steps, usually voluntary, that the public, business or industry could take to reduce emissions when higher levels of pollution are forecast to occur. As the 1999 rule notes, agencies may have several motivations for calling action days, including: providing health information to the public; attaining or maintaining NAAQS attainment status; meeting specific emission reduction targets; and managing or reducing traffic congestion. State, local and tribal agencies should consider whether non-voluntary emissions or activity curtailments are necessary (as opposed to a suite of voluntary measures) for days when the AQI is forecasted to be on the lower end of the moderate category.

[153] Exposures to 50 ppb have not been evaluated experimentally, but are estimated to potentially affect only a small proportion of healthy adults and with only a half to a third of the moderate to large lung function decrements observed at 60 ppb (McDonnell *et al.*, 2012; Figure 7).

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that the new AQI for O_3 can be implemented more easily in the public forum for which the AQI ultimately exists. However, the EPA recognized alternative approaches to viewing the evidence and information and solicited comment on the proposed revisions to the AQI.

With respect to reporting requirements (40 CFR part 58, section 58.50), EPA proposed to revise 40 CFR part 58, section 58.50 (c) to determine the areas subject to AQI reporting requirements based on the latest available census figures, rather than the most recent decennial U.S. census.[154] This change is consistent with our current practice of using the latest population figures to make monitoring requirements more responsive to changes in population.

B. Comments on Proposed Revisions to the AQI

EPA received many comments on the proposed changes to the AQI. Three issues came up in the comments, including: (1) Whether the AQI should be revised at all, even if the primary standard is revised; (2) whether an AQI value of 100 should be set equal to the level of the primary standard and the other breakpoints adjusted accordingly; and, (3) whether the AQI reporting requirements should be based on the latest available census figures rather than the most recent decennial census.

With respect to the first issue, some industry commenters stated that the AQI should not be revised at all, even if the level of the primary O_3 standard is revised. In support of this position, these commenters stated that the proposed conforming changes to the AQI would lower O_3 levels in each category, and would mean that air quality that is actually improving would be reported as less healthy. According to commenters, the revised AQI would fail to capture these improvements and potentially mislead the public into thinking that air quality has degraded and that EPA and state regulators are not doing their jobs. These commenters noted that there is no requirement to revise the AQI, and that the CAA does not tie the AQI to the standards, stating that the purpose of section 319(a) of the CAA is to provide a consistent, uniform means of gauging air quality. These commenters further asserted that EPA's proposed changes run counter to that uniformity by changing the air quality significance of a given index value and category and that retention of the current AQI breakpoints would allow continued uniform information on air quality. Commenters stated that it is important that the EPA clearly communicates that the immediate increases in moderate rated days are due to AQI breakpoint adjustment and not due to a sudden decline in air quality. One commenter estimated the increased proportion of days in the moderate category and above in 10 metropolitan areas for 2013 and also for 2025 for 4 cities from the original 10 that were estimated to attain a standard below 70 ppb, to compare with 2013. This commenter noted that the change in the proposed AQI breakpoint between "good" and "moderate" would result in a larger number of days that did not meet the "good" criteria. They went further to claim that the change in breakpoints would result in fewer "good" days in the year 2025 (using the new breakpoint) than occurred in 2013 (using the old breakpoints) despite substantial improvement in air quality over that time period.

On the other hand, state and local agencies and their organizations, environmental and medical groups, and members of the public overwhelmingly supported revising the AQI when the level of the standard is revised. Even state agencies that did not support revising the standard, expressed support for revising the AQI at the same time as the standard, if the standard is revised.

Recognizing the importance of the AQI as a communication tool that allows members of the public to take exposure reduction measures when air quality poses health risks, the EPA agrees with these comments about revising the AQI at the same time as the primary standard. The EPA agrees with state and local agency commenters that its historical approach of setting an AQI value of 100 equal to the level of the revised 8-hour primary O_3 standard is appropriate, both from a public health and a communication perspective.

EPA disagrees with commenters who stated that the AQI should not be linked to the primary standards. As noted in the August 4, 1999, rulemaking (64 FR 149, 42531) that established the current AQI, the EPA established the nationally uniform air quality index, called the Pollutant Standards Index (PSI), in 1976 to meet the needs of state and local agencies with the following advantages: It sends a clear and consistent message to the public by providing nationally uniform information on air quality; it is keyed as appropriate to the NAAQS and the Significant Harm Level which have a scientific basis relating air quality and public health; it is simple and easily understood by the public; it provides a framework for reflecting changes to the NAAQS; and it can be forecasted to provide advance information on air quality. Both the PSI and AQI have historically been normalized across pollutants by defining an index value of 100 as the numerical level of the short-term (*i.e.,* averaging time of 24-hours or less) primary NAAQS for each pollutant. Moreover, this approach does not mislead the public. Since the establishment of the AQI, the EPA and state and local air agencies and organizations have developed experience in educating the public about changes in the standards and, concurrently, related changes to AQI breakpoints and advisories. When the standards change, EPA and state and local agencies have tried to help the public understand that air quality is not getting worse, it's that the health evidence underlying the standards and the AQI has changed. EPA's Air Quality System (AQS), the primary repository for air quality monitoring data, is also adjusted to reflect the revised breakpoints. Specifically, all historical AQI values in AQS are recomputed with the revised breakpoints, so that all data queries and reports downstream of AQS will show appropriate trends in AQI values over time.[155]

In general, commenters who supported revising the AQI when the standard is revised, also supported setting an AQI value of 100 equal to the level of the 8-hour primary O_3 standard. The EPA agrees with these commenters. With respect to an AQI value of 100, the EPA is taking final action to set an AQI value of 100 equal to the level of the 8-hour primary standard at 70 ppb O_3.

With respect to proposed changes to other AQI breakpoints, some state and local agency commenters expressed general support for all the changes in O_3 breakpoints (in Table 2 of Appendix G). In addition, we received a few comments specifically about the breakpoint between the good and moderate categories. One state expressed the view that forecasting the AQI for O_3 is not an exact science, so it is important to provide a range large enough to reasonably predict O_3

[154] Under 40 CFR 58.50, any MSA with a population exceeding 350,000 is required to report AQI data.

[155] Although we do not contest the assertion that the new AQI breakpoints will lead to fewer green days in the near future, we do not agree that commenters' analysis sufficiently demonstrates that there would be fewer green days in 2025 than in 2013. In their analysis, they compared observed 2013 data with modeled 2025 data without doing any model performance evaluation for AQI categories or comparison of current year modeled and observed data. The current year observations are not directly comparable to the future-year modeling data without some such evaluation and, as such, we cannot support their quantitative conclusions.

concentrations for the following day (≥ 20 ppb). Although not supporting revision of the standard, this state recommended that if the primary standard was revised to 70 ppb, the lower end of moderate category should be set at 50 ppb to allow for a 20 ppb spread in that category. Several commenters recommending a breakpoint between the good and moderate categories of no higher than 50 ppb stated that this breakpoint should be set on health information, pointing to epidemiologic data and the World Health organization guidelines. The Agency agrees that AQI breakpoints should take into consideration health information when possible, and also that it is important for AQI categories to span ranges large enough to support accurate forecasting. The EPA is setting the breakpoint at the lower end of the moderate category at 55 ppb, which is 15 ppb below the level of the standard of 70 ppb. This is consistent with past practice of making a proportional adjustment to this AQI breakpoint, relative to an AQI value of 100 (*i.e.,* 70 ppb), and also retains the current practice of providing a 15 ppb range in the moderate category to allow for accurate forecasting. This level is below the lowest concentration (*i.e.,* 60 ppb) that has been shown in controlled human exposure studies of healthy adults to cause moderate lung function decrements (*i.e.,* FEV_1 decrements ≥ 10%, which could be adverse to people with lung disease), large lung function decrements (*i.e.,* FEV_1 decrements ≥ 20%) in a small proportion of people, and airway inflammation, notwithstanding the Administrator's judgment that there is uncertainty in the adversity of the effects shown to occur at 60 ppb.

We received fewer comments on proposed changes to the AQI values of 150, 200 and 300. Again, some state and local agency commenters expressed general support for proposed changes to the AQI. Some states specifically supported these breakpoints. However, a commenter suggested setting an AQI value at the lower end of the unhealthy category, at a level much lower than 85 ppb, since they state that it is a key threshold that is often used in air quality action day programs as a trigger to encourage specific behavior modifications or reduce emissions of O_3 precursors (*e.g.,* by taking public transportation to work). This commenter stated that setting the breakpoint at 85 ppb would, in the Agency's own rationale, not require the triggering of these pollution reduction measures until air quality threatened to impact 25% of people exposed. We disagree with this commenter because EPA does not have any requirements for voluntary programs. State and local air agencies have discretion to set the trigger for voluntary action programs at whatever level they choose, and they are currently set at different levels, not just at the unhealthy breakpoint specified in the comment. For example, Houston, Galveston and Brazoria TX metropolitan area calls ozone action days when air quality reaches the unhealthy for sensitive groups category. For more information about action days programs across the U.S. see the AirNow Web site (*www.airnow.gov*) and click on the link to AirNow Action Days. The unhealthy category represents air quality where there are general population-level effects. We believe that setting the breakpoint between the unhealthy for sensitive groups and unhealthy categories, at 85 ppb where, as discussed in section IIIA above, controlled human exposure studies of young, healthy adults exposed to O_3 while engaged in quasi-continuous moderate exercise for 6.6 hours indicate that up to 25% of exposed people are likely to have moderate lung function decrements and up to 7% are likely to have large lung function decrements (McDonnell *et al.*, 2012; Figure 7) is appropriate. A smaller proportion of inactive or less active individuals would be expected to experience lung function decrements at 85 ppb. Moreover, a breakpoint at 85 ppb allows for category ranges large enough for accurate forecasting. Accordingly, the EPA is adopting the proposed revisions to the AQI values of 150, 200 and 300.

As noted earlier, the EPA proposed to revise 40 CFR part 58, section 58.50(c) to determine the areas subject to AQI reporting requirements based on the latest available census figures, rather than the most recent decennial U.S. census.

A total of five state air monitoring agencies provided comments on this proposed change. Four agencies supported the proposal. One state commenter did not support the proposal, noting that the change would unnecessarily complicate AQI reporting and possibly increase reporting burdens in an unpredictable manner.

The EPA notes that the majority of monitoring network minimum requirements listed in Appendix D to Part 58 include a reference to ''latest available census figures.'' Minimum network requirements for O_3, $PM_{2.5}$, SO_2, and NO_2 all include this language in the regulatory text and monitoring agencies have successfully adopted these processes into their planning activities and the subsequent revision of their annual monitoring network plans which are posted for public review. Annual population estimates are easily obtainable from the U.S. Census Bureau and the EPA does not believe the burden in tracking these annual estimates is excessive or complicated.[156] Although the changes in year to year estimates are typically modest, there are MSAs that are approaching (or have recently exceeded) the 350,000 population AQI reporting limit and there is great value in having the AQI reported for these areas when the population threshold is exceeded versus waiting potentially up to 10 years for a revision to the decennial census. Accordingly, the EPA is finalizing the proposed revision to 40 CFR part 58, section 58.50(c) to require the AQI reporting requirements to be based on the latest available census figures.

One state requested additional guidance on the frequency of updating the AQI reporting threshold, and recommended linking the AQI reporting requirement evaluation with the annual air monitoring network plan requirements, and recommended requiring AQI reporting to begin no later than January 1 of the following year. The EPA notes that the census bureau estimates appear to be released around July 1 of each year which would not provide sufficient time for monitoring agencies to incorporate AQI reporting in their annual plans for that year, which are also due by July 1 each year. EPA believes that it should be unnecessary for monitoring agencies to wait until the implementation of the following year's annual plan (*i.e.,* approximately 18 months later) to begin AQI reporting. Accordingly, EPA is not at this time including a specific deadline for commencement of AQI reporting for newly-subject areas in 40 CFR part 58, but will work with agencies to implement additional AQI reporting as needed to ensure that information is being disseminated in a timely fashion.

C. Final Revisions to the AQI

For the reasons discussed above, the EPA is revising the AQI for O_3 by setting an AQI value of 100 equal to 70 ppb, 8-hour average, the level of the revised primary O_3 standard. The EPA is also revising the following breakpoints: An AQI value of 50 is set at 54 ppb; an AQI value of 150 is set at 85 ppb; an AQI value of 200 is set at 105 ppb; and an AQI value of 300 is set at 200 ppb. All of these levels are averaged over 8 hours. The revisions to all of the

[156] *http://www.census.gov/popest/data/metro/totals/2014/CBSA-EST2014-alldata.html.*

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breakpoints are based on estimated health outcomes at relevant ambient concentrations and to allow for each category to span at least a 15–20 ppb category range to allow for more accurate air pollution forecasting. The EPA believes that the revised breakpoints provide a balance between adjustments to reflect the health information supporting the revised O_3 standard and providing category ranges that are large enough to be forecasted accurately, so that the AQI can be implemented more easily in the public forum for which the AQI ultimately exists. With respect to AQI reporting requirements (40 CFR part 58, section 58.50), the EPA is revising 40 CFR part 58, section 58.50(c) to make the AQI reporting requirements based on the latest available census figures, rather than the most recent decennial U.S. census. This change is consistent with our current practice of using the latest population figures to make monitoring requirements more responsive to changes in population.

IV. Rationale for Decision on the Secondary Standard

A. Introduction

This section (IV) presents the rationale for the Administrator's decisions regarding the need to revise the current secondary standard for O_3, and the appropriate revision. Based on her consideration of the full body of welfare effects evidence and related analyses, including the evidence of effects associated with cumulative seasonal exposures of the magnitudes allowed by the current standard, the Administrator has concluded that the current secondary standard for O_3 does not provide the requisite protection of public welfare from known or anticipated adverse effects. She has decided to revise the level of the current secondary standard to 0.070 ppm, in conjunction with retaining the current indicator, averaging time and form.

The Administrator has made this decision based on judgments regarding the currently available welfare effects evidence, the appropriate degree of public welfare protection for the revised standard, and currently available air quality information on seasonal cumulative exposures that may be allowed by such a standard. In so doing, she has focused on O_3 effects on tree seedling growth as a proxy for the full array of vegetation-related effects of O_3, ranging from effects on sensitive species to broader ecosystem-level effects. Using this proxy in judging effects to public welfare, the Administrator has concluded that the requisite protection from adverse effects to public welfare will be provided by a standard that limits cumulative seasonal exposures to 17 ppm-hrs or lower, in terms of a 3-year W126 index, in nearly all instances, and she has also concluded that such control of cumulative seasonal exposures may be achieved by revising the level of the current standard to 70 ppb. Based on all of these considerations, the Administrator has decided that a secondary standard with a level of 0.070 ppm, and the current form and averaging time, will provide the requisite protection of public welfare from known or anticipated adverse effects.

As discussed more fully below, this decision is based on a thorough review, in the ISA, of the latest scientific information on O_3-induced environmental effects. This decision also takes into account (1) staff assessments in the PA of the most policy-relevant information in the ISA regarding evidence of adverse effects of O_3 to vegetation and ecosystems, information on biologically-relevant exposure metrics, WREA analyses of air quality, exposure, and ecological risks and associated ecosystem services, and staff analyses of relationships between levels of a W126-based metric and a metric based on the form and averaging time of the current standard summarized in the PA and in the proposal notice; (2) CASAC advice and recommendations; and (3) public comments received during the development of these documents, either in connection with CASAC meetings or separately, and on the proposal notice.

This decision draws on the ISA's integrative synthesis of the entire body of evidence, generally published through July 2011, on environmental effects associated with the presence of O_3 and related photochemical oxidants in the ambient air (U.S. EPA, 2013, ISA chapters 9–10), and includes more than four hundred new studies that build on the extensive evidence base from the last review. In addition to reviewing the most recent scientific information as required by the CAA, this rulemaking incorporates the EPA's response to the judicial remand of the 2008 secondary O_3 standard in *State of Mississippi* v. *EPA,* 744 F. 3d 1334 (D.C. Cir. 2013) and, in accordance with the court's decision in that case, fully explains the Administrator's conclusions as to the level of air quality that provides the requisite protection of public welfare from known or anticipated adverse effects. In drawing conclusions on the secondary standard, the decision described in this rulemaking is a public welfare policy judgment made by the Administrator. The Administrator's decision draws upon the available scientific evidence for O_3-attributable welfare effects and on analyses of exposures and public welfare risks based on impacts to vegetation, ecosystems and their associated services, as well as judgments about the appropriate weight to place on the range of uncertainties inherent in the evidence and analyses. As described in sections IV.B.3 and IV.C.3 below, such judgments in the context of this review include judgments on the weight to place on the evidence of specific vegetation-related effects estimated to result across a range of cumulative seasonal concentration-weighted O_3 exposures; on the weight to give associated uncertainties, including those related to the variability in occurrence of such effects in areas of the U.S., especially areas of particular public welfare significance; and on the extent to which such effects in such areas may be considered adverse to public welfare.

Information related to vegetation and ecosystem effects, biologically relevant exposure indices, and vegetation exposure and risk assessments were summarized in sections IV.A through IV.C of the proposal (79 FR at 75314–75329), respectively, and key observations from the proposal are briefly outlined in sections IV.A.1 to IV.A.3 below. Subsequent sections of this preamble provide a more complete discussion of the Administrator's rationale, in light of key issues raised in public comments, for concluding that the current standard is not requisite to protect public welfare from known or anticipated adverse effects (section IV.B), and that it is appropriate to revise the current secondary standard to provide additional public welfare protection by revising the level while retaining the current indicator, form and averaging time (section IV.C). A summary of the final decisions on revisions to the secondary standard is presented in section IV.D.

1. Overview of Welfare Effects Evidence

a. Nature of Effects

In the more than fifty years that have followed identification of O_3's phytotoxic effects, extensive research has been conducted both in and outside of the U.S. to examine the impacts of O_3 on plants and their associated ecosystems (U.S. EPA, 1978, 1986, 1996a, 2006a, 2013). As was established in prior reviews, O_3 can interfere with carbon gain (photosynthesis) and allocation of carbon within the plant, making fewer carbohydrates available

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for plant growth, reproduction, and/or yield. For seed-bearing plants, these reproductive effects will culminate in reduced seed production or yield (U.S. EPA, 1996a, pp. 5–28 and 5–29). Recent studies, assessed in the ISA, together with this longstanding and well-established literature on O_3-related vegetation effects, further contribute to the coherence and consistency of the vegetation effects evidence (U.S. EPA, 2013, chapter 9).

The strongest evidence for effects from O_3 exposure on vegetation is from controlled exposure studies, which ''have clearly shown that exposure to O_3 is causally linked to visible foliar injury, decreased photosynthesis, changes in reproduction, and decreased growth'' in many species of vegetation (U.S. EPA, 2013, p. 1–15). Such effects at the plant scale can also be linked to an array of effects at larger spatial scales, with the currently available evidence indicating that ''ambient O_3 exposures can affect ecosystem productivity, crop yield, water cycling, and ecosystem community composition'' (U.S. EPA, 2013, p. 1–15; Chapter 9, section 9.4). The current body of O_3 welfare effects evidence confirms and strengthens support for the conclusions reached in the last review on the nature of O_3-induced welfare effects and is summarized in the ISA as follows (U.S. EPA, 2013, p. 1–8).

> The welfare effects of O_3 can be observed across spatial scales, starting at the subcellular and cellular level, then the whole plant and finally, ecosystem-level processes. Ozone effects at small spatial scales, such as the leaf of an individual plant, can result in effects along a continuum of larger spatial scales. These effects include altered rates of leaf gas exchange, growth, and reproduction at the individual plant level, and can result in broad changes in ecosystems, such as productivity, carbon storage, water cycling, nutrient cycling, and community composition.

Based on assessment of this extensive body of science, the EPA has determined that, with respect to vegetation and ecosystems, a causal relationship exists between exposure to O_3 in ambient air and visible foliar injury effects on vegetation, reduced vegetation growth, reduced productivity in terrestrial ecosystems, reduced yield and quality of agricultural crops and alteration of below-ground biogeochemical cycles (U.S. EPA, 2013, Table 1–2). In consideration of the evidence of O_3 exposure and alterations in stomatal performance, ''which may affect plant and stand transpiration and therefore possibly affecting hydrological cycling,'' the ISA concludes that ''[a]lthough the direction of the response differed among studies,'' the evidence is sufficient to conclude a likely causal relationship between O_3 exposure and the alteration of ecosystem water cycling (U.S. EPA, 2013, section 2.6.3). The evidence is also sufficient to conclude a likely causal relationship between O_3 exposure and the alteration of community composition of some terrestrial ecosystems (U.S. EPA, 2013, section 2.6.5). Related to the effects on vegetation growth, productivity and, to some extent, below-ground biogeochemical cycles, the EPA has additionally determined that a likely causal relationship exists between exposures to O_3 in ambient air and reduced carbon sequestration (also termed carbon storage) in terrestrial ecosystems (U.S. EPA, 2013, p. 1–10 and section 2.6.2). Modeling studies available in this review consistently found negative impacts of O_3 on carbon sequestration, although the severity of impact was influenced by ''multiple interactions of biological and environmental factors'' (U.S. EPA, 2013, p. 2–39).

Ozone in the troposphere is also a major greenhouse gas and radiative forcing agent,[157] with the ISA formally concluding that ''the evidence supports a causal relationship between changes in tropospheric O_3 concentrations and radiative forcing'' (U.S. EPA, 2013, p. 1–13 and section 2.7.1). While tropospheric O_3 has been ranked third in importance after carbon dioxide and methane, there are ''large uncertainties in the magnitude of the radiative forcing estimate attributed to tropospheric O_3, making the impact of tropospheric O_3 on climate more uncertain than the effect of the longer-lived greenhouse gases'' (U.S. EPA, 2013, p. 2–47). The ISA notes that ''[e]ven with these uncertainties, global climate models indicate that tropospheric O_3 has contributed to observed changes in global mean and regional surface temperatures'' and concludes that ''[a]s a result of such evidence presented in climate modeling studies, there is likely to be a causal relationship between changes in tropospheric O_3 concentrations and effects on climate'' (U.S. EPA, 2013, p. 2–47).[158] The ISA additionally states that ''[i]mportant uncertainties remain regarding the effect of tropospheric O_3 on future climate change'' (U.S. EPA, 2013, p. 10–31).

[157] As described in the ISA, ''[r]adiative forcing by a greenhouse gas or aerosol is a metric used to quantify the change in balance between radiation coming into and going out of the atmosphere caused by the presence of that substance'' (U.S. EPA, 2013, p. 1–13).

[158] Climate responses, including increased surface temperature, have downstream climate-related ecosystem effects (U.S. EPA, 2013, p. 10–7). As noted in section I.D above, such effects may include an increase in the area burned by wildfires, which, in turn, are sources of O_3 precursor emissions.

b. Vegetation Effects

Given the strong evidence base and the findings of causal or likely causal relationships with O_3 in ambient air, including the quantitative assessments of relationships between O_3 exposure and occurrence and magnitude of effects, this review has given primary consideration to three main kinds of vegetation effects, some of which contribute to effects at scales beyond the plant level, such as at the ecosystem level and on ecosystem services. The three kinds of effects are addressed below in the following order: 1) Visible foliar injury, 2) impacts on tree growth, productivity and carbon storage, and 3) crop yield loss.

Visible foliar injury resulting from exposure to O_3 has been well characterized and documented over several decades of research on many tree, shrub, herbaceous, and crop species (U.S. EPA, 2013, p. 1–10; U.S. EPA, 2006a, 1996a, 1986, 1978). Ozone-induced visible foliar injury symptoms on certain plant species, such as black cherry, yellow-poplar and common milkweed, are considered diagnostic of exposure to O_3 based on the consistent association established with experimental evidence (U.S. EPA, 2013, p. 1–10). The evidence has found that visible foliar injury occurs only when sensitive plants are exposed to elevated O_3 concentrations in a predisposing environment; a major modifying factor is the amount of available soil moisture during the year (U.S. EPA, 2013, section 9.4.2).

The significance of O_3 injury at the leaf and whole plant levels depends on an array of factors, and therefore, it is difficult to quantitatively relate visible foliar injury symptoms to vegetation effects such as individual tree growth, or effects at population or ecosystem levels (U.S. EPA, 2013, p. 9–39). The ISA notes that visible foliar injury ''is not always a reliable indicator of other negative effects on vegetation'' (U.S. EPA, 2013, p. 9–39). Factors that influence the significance to the leaf and whole plant include the amount of total leaf area affected, age of plant, size, developmental stage, and degree of functional redundancy among the existing leaf area (U.S. EPA, 2013, section 9.4.2). Although there remains a lack of robust exposure-response functions that would allow prediction of visible foliar injury severity and incidence under varying air quality and environmental conditions, ''[e]xperimental evidence has clearly

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established a consistent association of visible injury with O_3 exposure, with greater exposure often resulting in greater and more prevalent injury'' (U.S. EPA, 2013, section 9.4.2, p. 9–41).

By far the most extensive field-based dataset of visible foliar injury incidence is that obtained by the U.S. Forest Service Forest Health Monitoring/Forest Inventory and Analysis (USFS FHM/FIA) biomonitoring network program (U.S. EPA, 2013, section 9.4.2.1; Smith, 2012; Coulston *et al.,* 2007). A recently published trend analysis of data from the sites located in 24 states of the northeast and north central U.S. for the 16-year period from 1994 through 2009 (Smith, 2012) describes evidence of visible foliar injury occurrence in the field as well as some insight into the influence of changes in air quality and soil moisture on visible foliar injury and the difficulty inherent in predicting foliar injury response under different air quality and soil moisture scenarios (Smith, 2012; U.S. EPA, 2013, section 9.4.2.1). Study results showed that incidence and severity of foliar injury were dependent on local site conditions for soil moisture availability and O_3 exposure (U.S. EPA, 2013, p. 9–41). Although the study indicated that moderate O_3 exposures continued to cause visible foliar injury at sites throughout the study area, there was an overall declining trend in the incidence of visible foliar injury as peak O_3 concentrations declined (U.S. EPA, 2013, p. 9–40).

Ozone has been shown to affect a number of important U.S. tree species with respect to growth, productivity, and carbon storage. Ambient O_3 concentrations have long been known to cause decreases in photosynthetic rates and plant growth. As discussed in the ISA, research published since the 2006 AQCD substantiates prior conclusions regarding O_3-related effects on forest tree growth, productivity and carbon storage, and further strengthens the support for those conclusions. A variety of factors in natural environments can either mitigate or exacerbate predicted O_3-plant interactions and are recognized sources of uncertainty and variability. Such factors include multiple genetically influenced determinants of O_3 sensitivity, changing sensitivity to O_3 across vegetative growth stages, co-occurring stressors and/or modifying environmental factors (U.S. EPA, 2013, section 9.4.8). In considering of the available evidence, the ISA states, ''previous O_3 AQCDs concluded that there is strong evidence that exposure to O_3 decreases photosynthesis and growth in numerous plant species'' and that ''[s]tudies published since the 2008 review support those conclusions'' (U.S. EPA, 2013, p. 9–42). The available studies come from a variety of different study types that cover an array of different species, effects endpoints, levels of biological organization and exposure methods and durations. The O_3-induced effects at the scale of the whole plant may translate to the ecosystem scale, with changes in productivity and carbon storage. As stated in the ISA, ''[s]tudies conducted during the past four decades have demonstrated unequivocally that O_3 alters biomass allocation and plant reproduction'' (U.S. EPA, 2013, p. 1–10).

The strong evidence of O_3 impacts on trees includes robust exposure-response (E–R) functions for reduced growth, termed relative biomass loss (RBL),[159] in seedlings of 11 species. These functions were developed under the National Health and Environmental Effects Research Laboratory-Western Ecology Division program, a series of experiments that used open top chambers (OTCs) to investigate seedling growth response for a single growing season under a variety of O_3 exposures (ranging from near background to well above current ambient concentrations) and growing conditions (U.S. EPA, 2013, section 9.6.2; Lee and Hogsett, 1996). The evidence from these studies shows that there is a wide range in sensitivity across the studied species in the seedling growth stage over the course of a single growing season, with some species being extremely sensitive and others being very insensitive over the range of cumulative O_3 exposures studied (U.S. EPA, 2014c, Figure 5–1). At the other end of the organizational spectrum, field-based studies of species growing in natural stands have compared observed plant responses across a number of different sites and/or years when exposed to varying ambient O_3 exposure conditions. For example, a study conducted in forest stands in the southern Appalachian Mountains during a period when O_3 concentrations exceeded the current standard found that the cumulative effects of O_3 decreased seasonal stem growth (measured as a change in circumference) by 30–50 percent for most of the examined tree species (*i.e.,* tulip poplar, black cherry, red maple, sugar maple) in a high-O_3 year in comparison to a low-O_3 year (U.S. EPA, 2013, section 9.4.3.1; McLaughlin *et al.,* 2007a). The study also reported that high ambient O_3 concentrations can increase whole-tree water use and in turn reduce late-season streamflow (McLaughlin *et al.*, 2007b; U.S. EPA, 2013, p. 9–43).

The magnitude of O_3 impact on ecosystem productivity and on forest composition can vary among plant communities based on several factors, including the type of stand or community in which the sensitive species occurs (*e.g.,* single species *versus* mixed canopy), the role or position of the species in the stand (*e.g.,* dominant, sub-dominant, canopy, understory), and the sensitivity of co-occurring species and environmental factors (*e.g.,* drought and other factors). For example, recent studies found O_3 to have little impact on white fir, but to greatly reduce growth of ponderosa pine in southern California locations, with associated reductions in ponderosa pine abundance in the community, and to cause decreased net primary production of most forest types in the mid-Atlantic region, with only small impacts on spruce-fir forest (U.S. EPA, 2013, section 9.4.3.4).

There is previously and newly available evidence of the potential for O_3 to alter biomass allocation and plant reproduction in seasons subsequent to exposure (U.S. EPA, 2013, section 9.4.3). For example, several studies published since the 2006 AQCD further demonstrate that O_3 can alter the timing of flowering and the number of flowers, fruits and seeds in herbaceous and woody plant species (U.S. EPA, 2013, section 9.4.3.3). Further, limited evidence in previous reviews reported that vegetation effects from a single year of exposure to elevated O_3 could be observed in the following year. For example, growth affected by a reduction in carbohydrate storage in one year may result in the limitation of growth in the following year. Such ''carry-over'' effects have been documented in the growth of some tree seedlings and in roots (U.S. EPA, 2013, section 9.4.8; Andersen *et al.,* 1997). In the current review, additional field-based evidence expands the EPA's understanding of the consequences of single and multi-year O_3 exposures in subsequent years.

A number of studies were conducted at a planted forest at the Aspen free-air carbon-dioxide and ozone enrichment (FACE) experiment site in Wisconsin. These studies, which occurred in a field setting (more similar to natural forest stands than OTC studies), observed tree growth responses when grown in single or two species stands within 30-m diameter rings and exposed over a period of ten years to existing ambient conditions and elevated O_3

[159] These functions for RBL estimate reduction in a year's growth as a percentage of that expected in the absence of O_3 (U.S. EPA, 2013, section 9.6.2; U.S. EPA, 2014b, section 6.2).

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concentrations. Some studies indicate the potential for carry-over effects, such as those showing that the effects of O_3 on birch seeds (reduced weight, germination, and starch levels) could lead to a negative impact on species regeneration in subsequent years, and that the O_3-attributable effect of reduced aspen bud size might have been related to the observed delay in spring leaf development. These effects suggest that elevated O_3 exposures have the potential to alter carbon metabolism of overwintering buds, which may have subsequent effects in the following year (Darbah, *et al.,* 2008, 2007; Riikonen *et al.,* 2008; U.S. EPA, 2013, section 9.4.3). Other studies found that, in addition to affecting tree heights, diameters, and main stem volumes in the aspen community, elevated O_3 over a 7-year study period was reported to increase the rate of conversion from a mixed aspen-birch community to a community dominated by the more tolerant birch, leading the authors to conclude that elevated O_3 may alter intra- and inter-species competition within a forest stand (U.S. EPA, 2013, section 9.4.3; Kubiske *et al.,* 2006; Kubiske *et al.,* 2007). These studies confirm earlier FACE results of aspen growth reductions from exposure to elevated O_3 during the first seven years of stand growth and of cumulative biomass impacts associated with changes in annual production in studied tree communities (U.S. EPA, 2013, section 9.4.3; King *et al.,* 2005).

Robust and well-established E–R functions for RBL are available for 11 tree species: black cherry, Douglas fir, loblolly pine, ponderosa pine, quaking aspen, red alder, red maple, sugar maple, tulip poplar, Virginia pine, and white pine (U.S. EPA, 2013; U.S. EPA, 2014c). While these 11 species represent only a small fraction (0.8 percent) of the total number of native tree species in the contiguous U.S. (1,497), this small subset includes eastern and western species, deciduous and coniferous species, and species that grow in a variety of ecosystems and represent a range of tolerance to O_3 (U.S. EPA, 2013, section 9.6.2; U.S. EPA, 2014b, section 6.2, Figure 6–2, Table 6–1). Supporting the E–R functions for each of these species are studies in OTCs, with most species studied multiple times under a wide range of exposure and/or growing conditions, with separate E–R functions developed for each combination of species, exposure condition and growing condition scenario (U.S. EPA, 2013, section 9.6.1). Based on these separate E–R functions, species-specific composite E–R functions have been developed and successfully used to predict the biomass loss response from tree seedling species over a range of cumulative exposure conditions (U.S. EPA, 2013, section 9.6.2). These 11 composite functions, as well as the E–R function for eastern cottonwood (derived from a field study in which O_3 and climate conditions were not controlled),[160] are described in the ISA and graphed in the WREA to illustrate the predicted responses of these species over a wide range of cumulative exposures (U.S. EPA, 2014b, section 6.2, Table 6–1 and Figure 6–2; U.S. EPA, 2013, section 9.6.2). For some of these species, the E–R function is based on a single study (*e.g.,* red maple), while for other species there were as many as 11 studies available (*e.g.,* ponderosa pine). In total, the E–R functions developed for these 12 species (the 11 with robust composite E–R functions plus eastern cottonwood) reflect 52 tree seedling studies. A stochastic analysis in the WREA, summarized in section IV.C of the proposal, indicates the potential for within-species variability in these relationships for each species. Consideration of biomass loss estimates in the PA and in discussions below, however, is based on conventional methods and focuses on estimates for the 11 species for which the robust datasets from OTC experiments are available, in consideration of CASAC advice.

The ''detrimental effect of O_3 on crop production has been recognized since the 1960s'' (U.S. EPA, 2013, p. 1–10, section 9.4.4). On the whole, the newly available evidence supports and strengthens previous conclusions that exposure to O_3 reduces growth and yield of crops. The ISA describes average crop yield loss reported across a number of recently published meta-analyses and identifies several new exposure studies that support prior findings for a variety of crops of decreased yield and biomass with increased O_3 exposure (U.S. EPA, 2013, section 9.4.4.1, Table 9–17). Studies have also ''linked increasing O_3 concentration to decreased photosynthetic rates and accelerated aging in leaves, which are related to yield'' and described effects of O_3 on crop quality, such as nutritive quality of grasses, macro- and micronutrient concentrations in fruits and vegetable crops and cotton fiber quality (U.S. EPA, 2013, p. 1–10, section 9.4.4). The findings of the newly available studies do not change the basic understanding of O_3-related crop yield loss since the last review and little additional information is available in this review on factors that influence associations between O_3 levels and crop yield loss (U.S. EPA, 2013, section 9.4.4.). However, the evidence available in this review continues to support the conclusion that O_3 in ambient air can reduce the yield of major commodity crops in the U.S. Further, the recent evidence increases our confidence in the use of crop E–R functions based on OTC experiments to characterize the quantitative relationship between ambient O_3 concentrations and yield loss (U.S. EPA, 2013, section 9.4.4).

The new evidence has strengthened support for previously established E–R functions for 10 crops (barley, field corn, cotton, kidney bean, lettuce, peanut, potato, grain sorghum, soybean and winter wheat), reducing two important areas of uncertainty, especially for soybean, as summarized in more detail in section IV.A of the proposal. The established E–R functions for relative yield loss (RYL)[161] were developed from OTC-type experiments from the National Crop Loss Assessment Network (NCLAN) (U.S. EPA, 2013, section 9.6.3; U.S. EPA, 2014b, section 6.2; U.S. EPA, 2014c, Figure 5–4 and section 6.3). With regard to the first area of uncertainty reduced, evaluations in the ISA found that yield loss in soybean from O_3 exposure at the SoyFACE (Soybean Free Air Concentration Enrichment) field experiment was reliably predicted by soybean E–R functions developed from NCLAN data (U.S. EPA, 2013, section 9.6.3.1),[162] demonstrating a robustness of the NCLAN-based E–R functions for predicting relative yield loss from O_3 exposure. A second area of uncertainty that was reduced is that regarding the

[160] The CASAC cautioned the EPA against placing too much emphasis on the eastern cottonwood data. In comments on the draft PA, the CASAC stated that the eastern cottonwood response data from a single study ''receive too much emphasis,'' explaining that these ''results are from a gradient study that did not control for ozone and climatic conditions and show extreme sensitivity to ozone compared to other studies'' and that ''[a]lthough they are important results, they are not as strong as those from other experiments that developed E–R functions based on controlled ozone exposure'' (Frey, 2014c, p. 10).

[161] These functions for RYL estimate reduction in a year's growth as a percentage of that expected in the absence of O_3 (U.S. EPA, 2013, section 9.6.2; U.S. EPA, 2014b, section 6.2).

[162] The NCLAN program, which was undertaken in the early to mid-1980s, assessed multiple U.S. crops, locations, and O_3 exposure levels, using consistent methods, to provide the largest, most uniform database on the effects of O_3 on agricultural crop yields (U.S. EPA 1996a; U.S. EPA, 2006a; U.S. EPA, 2013, sections 9.2, 9.4, and 9.6, Frey, 2014c, p. 9). The SoyFACE experiment was a chamberless (or free-air) field-based exposure study conducted in Illinois from 2001—2009 (U.S. EPA, 2013, section 9.2.4).

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application of the NCLAN E–R functions to more recent cultivars currently growing in the field. Recent studies, especially those focused on soybean, provide little evidence that crops are becoming more tolerant of O_3 (U.S. EPA, 2006a; U.S. EPA, 2013, sections 9.6.3.1 and 9.6.3.4 and p. 9–59). The ISA comparisons of NCLAN and SoyFACE data referenced above also ''confirm that the response of soybean yield to O_3 exposure has not changed in current cultivars'' (U.S. EPA, 2013, p. 9–59; section 9.6.3.1). Additionally, a recent assessment of the relationship between soybean yield loss and O_3 in ambient air over the contiguous area of Illinois, Iowa, and Indiana found a relationship that correlates well with previous results from FACE- and OTC-type experiments (U.S. EPA, 2013, section 9.4.4.1).

c. Biologically Relevant Exposure Metric

In assessing biologically based indices of exposure pertinent to O_3 effects on vegetation, the ISA states the following (U.S. EPA, 2013, p. 2–44).

> The main conclusions from the 1996 and 2006 O_3 AQCDs [Air Quality Criteria Documents] regarding indices based on ambient exposure remain valid. These key conclusions can be restated as follows: ozone effects in plants are cumulative; higher O_3 concentrations appear to be more important than lower concentrations in eliciting a response; plant sensitivity to O_3 varies with time of day and plant development stage; [and] quantifying exposure with indices that cumulate hourly O_3 concentrations and preferentially weight the higher concentrations improves the explanatory power of exposure/response models for growth and yield, over using indices based on mean and peak exposure values.

The long-standing body of available evidence upon which these conclusions are based includes a wealth of information on aspects of O_3 exposure that are important in influencing plant response (U.S. EPA, 1996a; U.S. EPA, 2006a; U.S. EPA, 2013). Specifically, a variety of ''factors with known or suspected bearing on the exposure-response relationship, including concentration, time of day, respite time, frequency of peak occurrence, plant phenology, predisposition, etc.,'' have been identified (U.S. EPA, 2013, section 9.5.2). In addition, the importance of the duration of the exposure and the relatively greater importance of higher concentrations over lower concentrations in determining plant response to O_3 have been consistently well documented (U.S. EPA, 2013, section 9.5.3). Based on improved understanding of the biological basis for plant response to O_3 exposure, a large number of ''mathematical approaches for summarizing ambient air quality information in biologically meaningful forms for O_3 vegetation effects assessment purposes'' have been developed (U.S. EPA, 2013, section 9.5.3), including those that cumulate exposures over some specified period while weighting higher concentrations more than lower (U.S. EPA, 2013, section 9.5.2). As with any summary statistic, these exposure indices retain information on some, but not all, characteristics of the original observations.

Based on extensive review of the published literature on different types of exposure-response metrics, including comparisons between metrics, the EPA has focused on cumulative, concentration-weighted indices, recognizing them as the most appropriate biologically based metrics to consider in this context (U.S. EPA, 1996a; U.S. EPA, 1996b; U.S. EPA, 2006a; U.S. EPA, 2013). In the last two reviews of the O_3 NAAQS, the EPA concluded that the risk to vegetation comes primarily from cumulative exposures to O_3 over a season or seasons [163] and focused on metrics intended to characterize such exposures: SUM06 [164] in the 1997 review (61 FR 65716, December 13, 1996) and W126 in the 2008 review (72 FR 37818, July 11, 2007). Although in both reviews the policy decision was made not to revise the form and averaging time of the secondary standard, the Administrator, in both cases, also concluded, consistent with CASAC advice, that a cumulative, seasonal index was the most biologically relevant way to relate exposure to plant growth response (62 FR 38856, July 18, 1997; 73 FR 16436, March 27, 2008). This approach for characterizing O_3 exposure concentrations that are biologically relevant with regard to potential vegetation effects received strong support from CASAC in the last review and again in this review, including strong support for use of such a metric as the form for the secondary standard (Henderson, 2006, 2008; Samet, 2010; Frey, 2014c).

Alternative methods for characterizing O_3 exposure to predict plant response have, in recent years, included flux models, which some researchers have claimed may ''better predict vegetation responses to O_3 than exposure-based approaches'' because they estimate the ambient O_3 concentration that actually enters the leaf (*i.e.,* flux or deposition). However, the ISA notes that ''[f]lux calculations are data intensive and must be carefully implemented'' (U.S. EPA, 2013, p. 9–114). Further, the ISA states, ''[t]his uptake-based approach to quantify the vegetation impact of O_3 requires inclusion of those factors that control the diurnal and seasonal O_3 flux to vegetation (*e.g.,* climate patterns, species and/or vegetation-type factors and site-specific factors)'' (U.S. EPA, 2013, p. 9–114). In addition to these data requirements, each species has different amounts of internal detoxification potential that may protect species to differing degrees. The lack of detailed species- and site-specific data required for flux modeling in the U.S. and the lack of understanding of detoxification processes have continued to make this technique less viable for use in vulnerability and risk assessments at the national scale in the U.S. (U.S. EPA, 2013, section 9.5.4).

Therefore, consistent with the ISA conclusions regarding the appropriateness of considering cumulative exposure indices that preferentially weight higher concentrations over lower for predicting O_3 effects of concern based on the well-established conclusions and supporting evidence described above, and in light of continued CASAC support, we continue to focus on cumulative concentration-weighted indices as the most biologically relevant metrics for consideration of O_3 exposures eliciting vegetation-related effects. Quantifying exposure in this way ''improves the explanatory power of exposure/response models for growth and yield over using indices based on mean and peak exposure values'' (U.S. EPA, 2013, section 2.6.6.1, p. 2–44). In this review, as in the last review, we use the W126-based cumulative, seasonal metric (U.S. EPA, 2013, sections 2.6.6.1 and 9.5.2) for consideration of the effects evidence and in the exposure and risk analyses in the WREA.

This metric, commonly called the W126 index, is a non-threshold approach described as the sigmoidally weighted sum of all hourly O_3 concentrations observed during a specified daily and seasonal time window, where each hourly O_3 concentration is given a weight that increases from zero to one with increasing concentration (U.S. EPA, 2014c, p. 5–6; U.S. EPA 2013, p. 9–101).

[163] In describing the form as ''seasonal,'' the EPA is referring generally to the growing season of O_3-sensitive vegetation, not to the seasons of the year (*i.e.,* spring, summer, fall, winter).

[164] The SUM06 index is a threshold-based approach described as the sum of all hourly O_3 concentrations greater or equal to 0.06 ppm observed during a specified daily and seasonal time window (U.S. EPA, 2013, section 9.5.2). The W126 index is a non-threshold approach, described more fully below.

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The first step in calculating the seasonal W126 index, as described and considered in this review, is to sum the weighted ambient O_3 concentrations during daylight hours (defined as 8:00 a.m. to 8:00 p.m.) within each calendar month, resulting in monthly index values (U.S. EPA, 2014b, pp. 4–5 to 4–6). As more completely described in the WREA, the monthly W126 index values are calculated from hourly O_3 concentrations as follows:

$$\textit{Monthly}\ \mathbf{W126} = \sum_{d=1}^{N} \sum_{h=8}^{19} \frac{C_{dh}}{1+4403*\exp(-126*C_{dh})}$$

where N is the number of days in the month, d is the day of the month (d = 1, 2, . . ., N), h is the hour of the day (h = 0, 1, . . ., 23), and C_{dh} is the hourly O_3 concentration observed on day d, hour h, in parts per million. The seasonal W126 index value for a specific year is the maximum sum of the monthly index values for three consecutive months. Three-year W126 index values are calculated by taking the average of seasonal W126 index values for three consecutive years (U.S. EPA, 2014b, pp. 4–5 to 4–6; Wells, 2014a).

2. Overview of Welfare Exposure and Risk Assessment

This section outlines the information presented in section IV.C of the proposal regarding the WREA conducted for this review, which built upon similar analyses performed in the last review. The WREA focuses primarily on analyses related to two types of effects on vegetation: Reduced growth (biomass loss) in both trees and agricultural crops, and foliar injury. The assessments of O_3-associated reduced growth in native trees and crops (specifically, RBL and RYL, respectively) include analysis of associated changes in related ecosystem services, including pollution removal, carbon sequestration or storage, and hydrology, as well as economic impacts on the forestry and agriculture sectors of the economy. The foliar injury assessments include cumulative analyses of the proportion of USFS biosite index scores [165] above zero (or five, in a separate set of analyses) with increasing W126 exposure index estimates, with and without consideration of soil moisture conditions. The implications of visible foliar injury in national parks were considered in a screening level assessment and three case studies.[166]

Growth-related effects were assessed for W126-based exposure estimates in five scenarios of national-scale [167] air quality: Recent conditions (2006 to 2008), the existing secondary standard, and W126 index values of 15 ppm-hrs, 11 ppm-hrs, and 7 ppm-hrs, using 3-year averages (U.S. EPA, 2014b, chapter 4). For each of these scenarios, 3-year average W126 exposure index values were estimated for 12 kilometer (km) by 12 km grid cells in a national-scale spatial surface. The method for creating these grid cell estimates generally involved two steps (summarized in Table 5–4 of the PA).

The first step in creating the grid cell estimates for each scenario was calculation of the average W126 index value (across the three years) at each monitor location. For the recent conditions scenario, this value was based on unadjusted O_3 concentrations from monitoring data. For the other four scenarios, the W126 index value for each monitor location was calculated from model-adjusted hourly O_3 concentrations. The adjusted concentrations were based on model-predicted relationships between O_3 at each monitor location and reductions in NO_X. Adjustments were applied independently for each of the nine U.S. regions (see U.S. EPA, 2014b, section 4.3.4.1).[168] The existing standard scenario was created first, with the result being a national dataset for which the highest monitor location in each U.S. region had a design value equal to the level of the current standard.[169] The W126 scenarios were created from the hourly concentrations used to create the existing standard scenario, with model-based adjustments made at all monitor sites in those regions with a site not already at or below the target W126 value for that scenario (U.S. EPA, 2014b, section 4.3.4.1).[170]

After completing step one for all the scenarios, the second step involved creating the national-scale spatial surfaces (composed of 3-year W126 index values at grid cell centroids). These were created by applying the Voronoi Neighbor Averaging (VNA) spatial interpolation technique to the monitor-location, 3-year W126 index values (described in step 1).[171] This step of creating the gridded spatial surfaces resulted in further reduction of the highest values in each modeling region, as demonstrated by comparing the W126 index values from steps one and two for the existing standard scenario. After the step-one adjustment of the monitor location concentrations such that the highest location in each NOAA region just met the existing standard (using relationships mentioned above), the maximum 3-year average W126 values in the nine regions ranged from 18.9 ppm-hrs in the West region to 2.6 ppm-hrs in the Northeast region (U.S. EPA, 2014b, Table 4–3). After application of the VNA technique in the second step, however, the highest 3-year average W126 values across the national surface grid cells, which were in the Southwest region, were below 15 ppm-hrs (U.S. EPA, 2014b, Figure 4–7).[172]

All of the assessments based on growth impacts relied on the W126 index estimates from the national-scale spatial surfaces (created from the 3-year average monitor location values as described above). Among the analyses related to visible foliar injury, a small component of the screening-level

[165] Sampling sites in the FIA/FHM O_3 biomonitoring program, called ''biosites'', are plots of land on which data are collected regarding the incidence and severity of visible foliar injury on a variety of O_3-sensitive plant species. Biosite index scores are derived from these data (U.S. EPA, 2014b, section 7.2.1).

[166] All of the analyses are described in detail in the WREA and summarized in the PA and in section IV.C of the proposal (U.S. EPA, 2014a; U.S. EPA, 2014b; 79 FR 75324–75329, December 17, 2014).

[167] Although the scenarios and the grid cell O_3 concentrations on which they are based were limited to the contiguous U.S., we have generally used the phrase ''national-scale'' in reference to the WREA scenarios and surfaces.

[168] The U.S. regions referenced here and in section IV.C below are NOAA climate regions, as shown in Figure 2B–1 of the PA.

[169] The adjustment results in broad regional reductions in O_3 and includes reductions in O_3 at some monitors that were already at or below the target level. These reductions do not represent an optimized control scenario, but rather characterize one potential distribution of air quality across a region that meets the scenario target (U.S. EPA, 2014b, sections 4.3.4.2 and 4.4).

[170] In regions where the air quality adjustment was applied, it was based on emissions reductions determined necessary for the highest monitor in that region to just equal the existing standard or the W126 target for the scenario. Concentrations at all other monitor locations in the region were also adjusted based on the same emissions reductions assumptions.

[171] The VNA technique is described in the WREA (U.S. EPA, 2014b, Appendix 4A).

[172] Thus, it can be seen that application of the VNA interpolation method to estimate W126 index values at the centroid of every 12 km x 12 km grid cell rather than only at each monitor location results in a lowering of the highest values in each region.

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national park assessment and also the three national park case studies involved summarizing 3-year W126 index estimates from the four air quality scenarios. However, the visible foliar injury cumulative proportion analyses and a component of the national park screening-level assessment relied on national-scale spatial surfaces of single-year, unadjusted W126 index values created for each year from 2006 through 2010 using the VNA interpolation technique applied to the monitor location index values for these years (U.S. EPA, 2014b, section 4.3.2, Appendix 4A).

Because the W126 estimates generated for the different air quality scenarios assessed are inputs to the vegetation risk analyses for tree biomass and crop yield loss, and also used in some components of the visible foliar injury assessments, limitations and uncertainties in the air quality analyses, which are discussed in detail in the WREA and some of which are mentioned here, are propagated into those analyses (U.S. EPA, 2014b, chapters 4 and 8 and section 8.5, Table 4–5). An important uncertainty in the analyses is the application of regionally determined emissions reductions to meet the existing standard (U.S. EPA, 2014b, section 8.5.1). The model adjustments are based on emissions reductions in NOx and characterize only one potential distribution of air quality across a region when all monitor locations meet the standard, as well as for the W126 scenarios (U.S. EPA, 2014b, section 4.3.4.2).[173]

An additional uncertainty related to the W126 index estimates in the national surfaces for each air quality scenario, and to the estimates for the single-year surfaces used in the visible foliar injury cumulative analysis, comes with the creation of the national-scale spatial surfaces of grid cells from the monitor-location O_3 data.[174] In general, spatial interpolation techniques perform better in areas where the O_3 monitoring network is denser. Therefore, the W126 index values estimated using this technique in rural areas in the West, Northwest, Southwest, and West North Central regions where there are few or no monitors (U.S. EPA, 2014b, Figure 2–1) are more uncertain than those estimated for areas with denser monitoring. Further, as described above, this interpolation method generally underpredicts the highest W126 exposure index values. Due to the important influence of higher exposures in determining risks to plants, the potential for the VNA interpolation approach to dampen peak W126 index values could result in an underestimation of risks to vegetation in some areas.[175]

The vegetation analyses performed in the WREA, along with key observations, insights, uncertainties and limitations were summarized in sections IV.C.2 through IV.C.3 of the proposal. Highlights for the three categories of biomass loss and foliar injury assessments are summarized here.

a. Tree Growth, Productivity and Carbon Storage

These assessments rely on the species-specific E–R functions described in section IV.A.1.b above. For the air quality scenarios described above, the WREA applied the species-specific E–R functions to develop estimates of O_3-associated RBL and associated effects on productivity, carbon storage and associated ecosystem services (U.S. EPA, 2014b, Chapter 6). More specifically, the WREA derived species-specific and weighted RBL estimates for grid cells across the continental U.S. and summarized the estimates by counties and national parks. Additional WREA case study analyses focused on selected urban areas. The WREA estimates indicate substantial heterogeneity in plant responses to O_3, both within species (*e.g.,* study-specific variation), between species, and across regions of the U.S. National variability in the estimates (*e.g.,* eastern vs western U.S.) is influenced by there being different sets of resident species (with different E–R functions) in different areas of the U.S., as well as differences in number of national parks and O_3 monitors. For example, the eastern U.S. has different resident species compared to the western U.S., and the eastern U.S. has far more such species. Additionally, there are more national parks in the western than the eastern U.S., yet fewer O_3 monitors (U.S. EPA, 2014b, chapter 8).

Relative biomass loss nationally (across all of the air quality surface grid cells) was estimated for each of the 12 studied species from the composite E–R functions for each species described above and information on the distribution of those species across the U.S. (U.S. EPA, 2014b, section 6.2.1.3 and Appendix 6A). In consideration of CASAC advice (summarized in section IV.A.1.b above), the WREA derived RBL and weighted RBL (wRBL) estimates separately, both with and without the eastern cottonwood, and the PA and proposal gave primary focus to analyses that exclude cottonwood. These analyses provided estimates of per-species and cross-species RBL in the different air quality scenarios. Air quality scenario estimates were also developed in terms of proportion of basal area affected at different magnitudes of RBL. The wRBL analysis integrated the species-specific estimates, providing an indication of potential magnitude of ecological effect possible in some ecosystems. The county analyses also included analyses focused on the median species response. The WREA also used the E–R functions to estimate RBL across tree lifespans and the resulting changes in consumer and producer/farmer economic surplus in the forestry and agriculture sectors of the economy. Case studies in five urban areas provided comparisons across air quality scenarios of estimates for urban tree pollutant removal and carbon storage or sequestration.

The array of uncertainties associated with estimates from these tree RBL analyses are summarized in the proposal and described in detail in the WREA, including the potential for the air quality scenarios to underestimate the higher W126 index values and associated implications for the RBL-related estimates, as referenced above.

b. Crop Yield Loss

These assessments rely on the species-specific E–R functions described in section IV.A.1.b above. For the different air quality scenarios, the WREA applied the species-specific E–R functions to develop estimates of O_3 impacts related to crop yield, including annual yield losses estimated for 10 commodity crops grown in the U.S. and how these losses affect producer and consumer economic surpluses (U.S. EPA, 2014b, sections 6.2, 6.5). The WREA derived estimates of crop RYL nationally and in a county-specific analysis, relying on information regarding crop distribution (U.S. EPA, 2014b, section 6.5). As with the tree analyses described above, the county analysis included estimates based on

[173] The adjustment is applied to all monitor locations in each region. In this way, the adjustment results in broad regional reductions in O_3 and includes reductions in O_3 at some monitors that were already meeting or below the target level. Thus, the adjustments performed to develop a scenario meeting a target level at the highest monitor in each region did result in substantial reduction below the target level in some areas of the region. This result at the monitors already well below the target indicates an uncertainty with regard to air quality expected from specific control strategies that might be implemented to meet a particular target level.

[174] Some uncertainty is inherent in any approach to characterizing O_3 air quality over broad geographic areas based on concentrations at monitor locations.

[175] In the visible foliar injury dataset used for the cumulative analysis, underestimation of W126 index values at sites with injury would contribute to overestimates of the cumulative proportion of sites with injury plotted for the lower W126 values.

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the median O_3 response across the studied crop species (U.S. EPA, 2014b, section 6.5.1, Appendix 6B).

Overall effects on agricultural yields and producer and consumer surplus depend on the ability of producers/farmers to substitute other crops that are less O_3 sensitive, and the responsiveness, or elasticity, of demand and supply (U.S. EPA, 2014b, section 6.5). The WREA discusses multiple areas of uncertainty associated with the crop yield loss estimates, including those associated with the model-based adjustment methodology as well as those associated with the projection of yield loss using the Forest and Agriculture Sector Optimization Model (with greenhouse gases) at the estimated O_3 concentrations (U.S. EPA, 2014b, Table 6–27, section 8.5). Because the W126 index estimates generated in the air quality scenarios are inputs to the vegetation risk analyses for crop yield loss, any uncertainties in the air quality scenario estimation of W126 index values are propagated into those analyses (U.S. EPA, 2014b, Table 6–27, section 8.5). Therefore, the air quality scenarios in the crop yield analyses have the same uncertainties and limitations as in the biomass loss analyses (summarized above), including those associated with the model-based adjustment methodology (U.S. EPA, 2014b, section 8.5).

c. Visible Foliar Injury

The WREA presents a number of analyses of O_3-related visible foliar injury and associated ecosystem services impacts (U.S. EPA, 2014b, Chapter 7). In the initial analysis, the WREA used the biomonitoring site data from the USFS FHM/FIA Network (USFS, 2011),[176] associated soil moisture data during the sample years, and national surfaces of ambient air O_3 concentrations based on spatial interpolation of monitoring data from 2006 to 2010 in a cumulative analysis of the proportion of biosite records with any visible foliar injury, as indicated by a nonzero biosite index score (U.S. EPA, 2014b, section 7.2). This analysis was done for all records together, and also for subsets based on soil moisture conditions (normal, wet or dry).

In each cumulative analysis, the biosite records were ordered by W126 index and then, moving from low to high W126 index, the records were cumulated into a progressively larger dataset. With the addition of each new data point (composed of biosite index score and W126 index value for a biosite and year combination) to the cumulative dataset, the percentage of sites with a nonzero biosite index score was derived and plotted versus the W126 index estimate for the just added data point. The cumulative analysis for all sites indicates that (1) as the cumulative set of sites grows with addition of sites with progressively higher W126 index values, the proportion of the dataset for which no foliar injury was recorded changes (increases) noticeably prior to about 10 ppm-hrs (10.46 ppm-hrs), and (2) as the cumulative dataset grows still larger with the addition of records for higher W126 index estimates, the proportion of the cumulative dataset with no foliar injury remains relatively constant (U.S. EPA, 2014b, Figure 7–10). The data for normal moisture years are very similar to the dataset as a whole, with an overall proportion of about 18 percent for presence of any foliar injury. The data for relatively wet years have a much higher proportion of biosites showing injury, approximately 25% when all data are included, and a proportion of approximately 20% when data for W126 index estimates up to about 5–8 ppm-hrs are included (U.S. EPA, 2014b, Figure 7–10).[177] The overall proportion showing injury for the subset for relatively dry conditions is much lower, less than 15% for the subset (U.S. EPA, 2014b, section 7.2.3, Figures 7–10). While these analyses indicate the potential for foliar injury to occur under conditions that meet the current standard, the extent of foliar injury that might be expected under different exposure conditions is unclear from these analyses.

Criteria derived from the cumulative analyses were then used in two additional analyses. The national-scale screening-level assessment compared W126 index values estimated within 214 national parks using the VNA technique described above for the individual years from 2006 to 2010 with benchmark criteria developed from the biosite data analysis (U.S. EPA, 2014b, Appendix 7A and section 7.3). Separate case study analyses described visits, as well as visitor uses and expenditures for three national parks, and the 3-year W126 index estimates in those parks for the four air quality scenarios (U.S. EPA, 2014b, section 7.4). Uncertainties associated with these analyses, included those associated with the W126 index estimates, are discussed in the WREA, sections 7.5 and 8.5.3, and in WREA Table 7–24, and also summarized in the PA (*e.g.,* U.S. EPA, 2014c, section 6.3).

3. Potential Impacts on Public Welfare

As provided in the CAA, section 109(b)(2), the secondary standard is to ''specify a level of air quality the attainment and maintenance of which in the judgment of the Administrator . . . is requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air.'' Effects on welfare include, but are not limited to, ''effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being'' (CAA section 302(h)). The secondary standard is not meant to protect against all known or anticipated O_3-related effects, but rather those that are judged to be adverse to the public welfare, and a bright-line determination of adversity is not required in judging what is requisite (78 FR 8312, January 15, 2013; see also 73 FR 16496, March 27, 2008). Thus, the level of protection from known or anticipated adverse effects to public welfare that is requisite for the secondary standard is a public welfare policy judgment to be made by the Administrator. In the current review, the Administrator's judgment is informed by conclusions drawn with regard to adversity of effects to public welfare in decisions on secondary O_3 standards in past reviews.

As indicated by the Administrator in the 2008 decision, the degree to which O_3 effects on vegetation should be considered to be adverse to the public welfare depends on the intended use of the vegetation and the significance of the vegetation to the public welfare (73 FR 16496, March 27, 2008). Such judgments regarding public welfare significance in the last O_3 NAAQS decision gave particular consideration to O_3 effects in areas with special federal protections, and lands set aside by states, tribes and public interest groups to provide similar benefits to the public welfare (73 FR 16496, March 27, 2008). For example, in reaching his conclusion regarding the need for revision of the secondary standard in the 2008 review, the Administrator took

[176] Data were not available for several western states (Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, New Mexico, Oklahoma, and portions of Texas).

[177] As discussed in section IV.C.2 below, as the cumulative set increases, with increasing W126 values, the overall prevalence of visible foliar injury in the cumulative set is more and more influenced by data for the lower W126 values. Accordingly, the ''leveling off'' observed above ~10 ppm-hrs in the 'all sites' analysis likely reflects the counterbalancing of visible foliar injury occurrence at the relatively fewer higher O_3 sites by the larger representation within the subset of the lower W126 conditions associated with which there is lower occurrence or extent of foliar injury.

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note of ''a number of actions taken by Congress to establish public lands that are set aside for specific uses that are intended to provide benefits to the public welfare, including lands that are to be protected so as to conserve the scenic value and the natural vegetation and wildlife within such areas, and to leave them unimpaired for the enjoyment of future generations'' (73 FR 16496, March 27, 2008). As further recognized in the 2008 notice, ''[s]uch public lands that are protected areas of national interest include national parks and forests, wildlife refuges, and wilderness areas'' (73 FR 16496, March 27, 2008).[178] [179] Such areas include Class I areas[180] which are federally mandated to preserve certain air quality related values. Additionally, as the Administrator recognized, ''States, Tribes and public interest groups also set aside areas that are intended to provide similar benefits to the public welfare, for residents on State and Tribal lands, as well as for visitors to those areas'' (73 FR 16496, March 27, 2008). The Administrator took note of the ''clear public interest in and value of maintaining these areas in a condition that does not impair their intended use and the fact that many of these lands contain O_3-sensitive species'' (73 FR 16496, March 27, 2008).

The concept described in the 2008 notice regarding the degree to which effects on vegetation in specially protected areas, such as those identified above, may be judged adverse also applies beyond the species level to the ecosystem level, such that judgments can depend on the intended use[181] for, or service (and value) of, the affected vegetation, ecological receptors, ecosystems and resources and the significance of that use to the public welfare (73 FR 16496, March 27, 2008). Uses or services provided by areas that have been afforded special protection can flow in part or entirely from the vegetation that grows there. Aesthetic value and outdoor recreation depend, at least in part, on the perceived scenic beauty of the environment (U.S. EPA, 2014b, chapters 5 and 7). Further, analyses have reported that the American public values—in monetary as well as nonmonetary ways—the protection of forests from air pollution damage. In fact, studies that have assessed willingness-to-pay for spruce-fir forest protection in the southeastern U.S. from air pollution and insect damage have found that values held by the survey respondents for the more abstract services (existence, option and bequest)[182] were greater than those for recreation or other services (U.S. EPA, 2014b, Table 5–6; Haefele *et al.,* 1991; Holmes and Kramer, 1995).

The spatial, temporal and social dimensions of public welfare impacts are also influenced by the type of service affected. For example, a national park can provide direct recreational services to the thousands of visitors that come each year, but also provide an indirect value to the millions who may not visit but receive satisfaction from knowing it exists and is preserved for the future (U.S. EPA, 2014b, chapter 5, section 5.5.1). Similarly, ecosystem services can be realized over a range of temporal scales. An evaluation of adversity to the public welfare might also consider the likelihood, type, and magnitude of the effect, as well as the potential for recovery and any uncertainties relating to these conditions, as stated in the preamble of the 2012 final notice of rulemaking on the secondary standards for oxides of nitrogen and sulfur (77 FR 20232, April 3, 2012).

The three main categories of effects on vegetation discussed in section IV.A.1.b above differ with regard to aspects important to judging their public welfare significance. Judgments regarding crop yield loss, for example, depend on considerations related to the heavy management of agriculture in the U.S., while judgments regarding the other categories of effects generally relate to considerations regarding forested areas. For example, while both tree growth-related effects and visible foliar injury have the potential to be significant to the public welfare through impacts in Class I and other protected areas, they differ in how they might be significant and with regard to the clarity of the data that describe the relationship between the effect and the services potentially affected.

With regard to effects on tree growth, reduced growth is associated with effects on an array of ecosystem services including reduced productivity, altered forest and forest community (plant, insect and microbe) composition, reduced carbon storage and altered water cycling (U.S. EPA, 2013, Figure 9–1, sections 9.4.1.1 and 9.4.1.2; U.S. EPA, 2014b, section 6.1). For example, forest or forest community composition can be affected through O_3 effects on growth and reproductive success of sensitive species in the community, with the extent of compositional changes dependent on factors such as competitive interactions (U.S. EPA, 2013, sections 9.4.3 and 9.4.3.1). Depending on the type and location of the affected ecosystem, services benefitting the public in other ways can be affected as well. For example, other services valued by people that can be affected by reduced tree growth, productivity and carbon storage include aesthetic value, food, fiber, timber, other forest products, habitat, recreational opportunities, climate and water regulation, erosion control, air pollution removal, and desired fire regimes (U.S. EPA 2013, sections 9.4.1.1 and 9.4.1.2; U.S. EPA, 2014b, section 6.1, Figure 6–1, section 6.4, Table 6–13). Further, impacts on some of these services (*e.g.,* forest or forest community composition) may be considered of greater public welfare significance when occurring in Class I or other protected areas.

Consideration of the magnitude of tree growth effects that might cause or contribute to adverse effects for trees, forests, forested ecosystems or the public welfare is complicated by aspects

[178] For example, the National Park Service Organic Act of 1916 established the National Park Service (NPS) and, in describing the role of the NPS with regard to ''Federal areas known as national parks, monuments, and reservations'', stated that the ''fundamental purpose'' for these federal areas ''is to conserve the scenery and the natural and historic objects and the wild life therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations.'' 16 U.S.C. 1.

[179] As a second example, the Wilderness Act of 1964 defines designated ''wilderness areas'' in part as areas ''protected and managed so as to preserve [their] natural conditions'' and requires that these areas ''shall be administered for the use and enjoyment of the American people in such manner as will leave them unimpaired for future use and enjoyment as wilderness, and so as to provide for the protection of these areas, [and] the preservation of their wilderness character . . .'' 16 U.S.C. 1131 (a).

[180] Areas designated as Class I include all international parks, national wilderness areas which exceed 5,000 acres in size, national memorial parks which exceed 5,000 acres in size, and national parks which exceed six thousand acres in size, provided the park or wilderness area was in existence on August 7, 1977. Other areas may also be Class I if designated as Class I consistent with the CAA.

[181] Ecosystem services have been defined as ''the benefits that people obtain from ecosystems'' (U.S. EPA, 2013, Preamble, p. 1xxii; UNEP, 2003) and thus are an aspect of the use of a type of vegetation or ecosystem. Similarly, a definition used for the purposes of the EPA benefits assessments states that ecological goods and services are the ''outputs of ecological functions or processes that directly or indirectly contribute to social welfare or have the potential to do so in the future'' and that ''[s]ome outputs may be bought and sold, but most are not marketed'' (U.S. EPA, 2006b). Ecosystem services analyses were one of the tools used in the last review of the secondary standards for oxides of nitrogen and sulfur to inform the decisions made with regard to adequacy and as such, were used in conjunction with other considerations in the discussion of adversity to public welfare (77 FR 20241, April 3, 2012).

[182] Public surveys have indicated that Americans rank as very important the existence of resources, the option or availability of the resource and the ability to bequest or pass it on to future generations (Cordell *et al.,* 2008).

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of, or limitations in, the available information. For example, the evidence on tree seedling growth effects, deriving from the E–R functions for 11 species (described in section IV.A.1 above), provides no clear threshold or breakpoint in the response to O_3 exposure. Additionally, there are no established relationships between magnitude of tree seedling growth reduction and forest ecosystem impacts and, as noted in section IV.A.1.b above, other factors can influence the degree to which O_3-induced growth effects in a sensitive species affect forest and forest community composition and other ecosystem service flows from forested ecosystems. These include (1) the type of stand or community in which the sensitive species is found (*i.e.,* single species versus mixed canopy); (2) the role or position the species has in the stand (*i.e.,* dominant, sub-dominant, canopy, understory); (3) the O_3 sensitivity of the other co-occurring species (O_3 sensitive or tolerant); and (4) environmental factors, such as soil moisture and others. The lack of such established relationships complicates judgments as to the extent to which different estimates of impacts on tree seedling growth would indicate significance to the public welfare and thus be an important consideration in the level of protection for the secondary standard.

During the 1997 review of the secondary standard, views related to this issue were provided by a 1996 workshop of 16 leading scientists in the context of discussing their views for a secondary O_3 standard (Heck and Cowling, 1997). In their consideration of tree growth effects as an indicator for forest ecosystems and crop yield reduction as an indicator of agricultural systems, the workshop participants identified annual percentages, of RBL for forest tree seedlings and RYL for agricultural crops, considered important to their judgments on the standard. With regard to forest ecosystems and seedling growth effects as an indicator, the participants selected a range of 1–2% RBL per year "to avoid cumulative effects of yearly reductions of 2%." With regard to crops, they indicated an interest in protecting against crop yield reductions of 5% RYL yet noted uncertainties surrounding such a percentage which led them to identifying 10% RYL for the crop yield endpoint (Heck and Cowling, 1997). The workshop report provides no explicit rationale for the percentages identified (1–2% RBL and 5% or 10% RYL); nor does it describe their connection to ecosystem impacts of a specific magnitude or type, nor to judgments on significance of the identified effects for public welfare, *e.g.,* taking into consideration the intended use and significance of the affected vegetation (Heck and Cowling, 1997). In recognition of the complexity of assessing the adversity of tree growth effects and effects on crop yield in the broader context of public welfare, the EPA's consideration of those effects in both the 1997 and 2008 reviews extended beyond the consideration of various benchmark responses for the studied species, and, with regard to crops, additionally took note of their extensive management (62 FR 38856, July 18, 1997; 73 FR 16436, March 27, 2008).

While, as noted above, public welfare benefits of forested lands can be particular to the type of area in which the forest occurs, some of the potential public welfare benefits associated with forest ecosystems are not location dependent. A potentially extremely valuable ecosystem service provided by forested lands is carbon storage, a regulating service that is "of paramount importance for human society" (U.S. EPA, 2013, section 2.6.2.1 and p. 9–37). As noted above, the EPA has concluded that this ecosystem service has a likely causal relationship with O_3 in ambient air. The service of carbon storage is potentially important to the public welfare no matter in what location the sensitive trees are growing or what their intended current or future use. In other words, the benefit exists as long as the tree is growing, regardless of what additional functions and services it provides. Another example of locations potentially vulnerable to O_3-related impacts but not necessarily identified for such protection might be forested lands, both public and private, where trees are grown for timber production. Forests in urbanized areas also provide a number of services that are important to the public in those areas, such as air pollution removal, cooling, and beautification. There are also many other tree species, such as species identified by the USFS and various ornamental and agricultural species (*e.g.,* Christmas trees, fruit and nut trees), that provide ecosystem services that may be judged important to the public welfare but whose vulnerability to O_3 impacts has not been quantitatively characterized (U.S. EPA, 2014b, Chapter 6).

As noted above, in addition to tree growth-related effects, O_3-induced visible foliar injury also has the potential to be significant to the public welfare through impacts in Class I and other similarly protected areas. Visible foliar injury is a visible bioindicator of O_3 exposure in species sensitive to this effect, with the injury affecting the physical appearance of the plant. Accordingly visible foliar injury surveys are used by federal land managers as tools in assessing potential air quality impacts in Class I areas. These surveys may focus on plant species that have been identified as potentially sensitive air quality related values (AQRVs) due to their sensitivity to O_3-induced foliar injury (USFS, NPS, FWS, 2010). An AQRV is defined by the National Park Service as a "resource, as identified by the [federal land manager] for one or more Federal areas that may be adversely affected by a change in air quality," and the resource "may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the [federal land manager] for a particular area" (USFS, NPS, USFWS, 2010).[183] No criteria have been established, however, regarding a level or prevalence of visible foliar injury considered to be adverse to the affected vegetation, and, as noted in section IV.A.1.b above, there is not a clear relationship between visible foliar injury and other effects, such as reduced growth and productivity.[184] Thus, key considerations with regard to public welfare significance of this endpoint

[183] The identification, monitoring and assessment of AQRVs with regard to an adverse effect is an approach used for assessing the potential for air pollution impacts in Class I areas from pending permit actions (USFS, NPS, USFWS, 2010). An adverse impact is recognized by the National Park Service as one that results in diminishment of the Class I area's national significance or the impairment of the ecosystem structure or functioning, as well as impairment of the quality of the visitor experience (USFS, NPS, USFWS, 2010). Federal land managers make such adverse impact determinations on a case-by-case basis, using technical and other information that they provide for consideration by permitting authorities. The National Park Service has developed a document describing an overview of approaches related to assessing projects under the National Environmental Policy Act and other planning initiatives affecting the National Park System (*http://www.nature.nps.gov/air/Pubs/pdf/AQGuidance_2011-01-14.pdf*).

[184] The National Park Service identifies various ranges of W126 index values in providing approaches for assessing air quality-related impacts of various development projects which appear to be based on the 1996 workshop report (Heck and Cowling, 1997), and may, at the low end, relate to a benchmark derived for the highly sensitive species, black cherry, for growth effects (10% RBL), rather than visible foliar injury (Kohut, 2007; Lefohn *et al.,* 1997). As noted in section IV.A.1.b above, visible foliar injury is not always a reliable indicator of other negative effects on vegetation (U.S. EPA, 2013, p. 9–39). We also note that the USFS biomonitoring analyses of visible foliar injury biomonitoring data commonly make use of a set of biosite index categories for which risk assumptions have been assigned, providing a relative scale of possible impacts (Campbell *et al,* 2007); however, little information is available on the studies, effects and judgments on which these categories are based.

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have related to qualitative consideration of the plant's aesthetic value in protected forested areas. Depending on the extent and severity, O_3-induced visible foliar injury might be expected to have the potential to impact the public welfare in scenic and/or recreational areas during the growing season, particularly in areas with special protection, such as Class I areas.

The ecosystem services most likely to be affected by O_3-induced visible foliar injury (some of which are also recognized above for tree growth-related effects) are cultural services, including aesthetic value and outdoor recreation. In addition, several tribes have indicated that many of the species identified as O_3 sensitive (including bioindicator species) are culturally significant (U.S. EPA, 2014c, Table 5–1). The geographic extent of protected areas that may be vulnerable to such public welfare effects of O_3 is potentially appreciable. Sixty-six plant species that occur on U.S. National Park Service (NPS) and U.S. Fish and Wildlife Service lands [185] have been identified as sensitive to O_3-induced visible foliar injury, and some also have particular cultural importance to some tribes (U.S. EPA, 2014c, Table 5–1 and Appendix 5–A; U.S. EPA, 2014b, section 6.4.2). Not all species are equally sensitive to O_3, however, and quantitative E–R relationships for O_3 exposure and other important effects, such as seedling growth reduction, are only available for a subset of 12 of the 66, as summarized in section IV.A.1.b above. A diverse array of ecosystem services has been identified for these twelve species (U.S. EPA, 2014c, Table 5–1). Two species in this group that are slightly more sensitive than the median for the group with regard to effects on growth are the ponderosa pine and quaking aspen (U.S. EPA, 2014b, section 6.2), the ranges for which overlap with many lands that are protected or preserved for enjoyment of current and future generations (consistent with the discussion above on Class I and other protected areas), including such lands located in the west and southwest regions of the U.S. where ambient O_3 concentrations and associated cumulative seasonal exposures can be highest (U.S. EPA, 2014c, Appendix 2B).[186]

With regard to agriculture-related effects, the EPA has recognized other complexities, stating that the degree to which O_3 impacts on vegetation that could occur in areas and on species that are already heavily managed to obtain a particular output (such as commodity crops or commercial timber production) would impair the intended use at a level that might be judged adverse to the public welfare has been less clear (73 FR 16497, March 27, 2008). As noted in section IV.B.2 of the proposal, while having sufficient crop yields is of high public welfare value, important commodity crops are typically heavily managed to produce optimum yields. Moreover, based on the economic theory of supply and demand, increases in crop yields would be expected to result in lower prices for affected crops and their associated goods, which would primarily benefit consumers. These competing impacts on producers and consumers complicate consideration of these effects in terms of potential adversity to the public welfare (U.S. EPA, 2014c, sections 5.3.2 and 5.7). When agricultural impacts or vegetation effects in other areas are contrasted with the emphasis on forest ecosystem effects in Class I and similarly protected areas, it can be seen that the Administrator has in past reviews judged the significance to the public welfare of O_3-induced effects on sensitive vegetation growing within the U.S. to differ depending on the nature of the effect, the intended use of the sensitive plants or ecosystems, and the types of environments in which the sensitive vegetation and ecosystems are located, with greater significance ascribed to areas identified for specific uses and benefits to the public welfare, such as Class I areas, than to areas for which such uses have not been established (FR 73 16496–16497, March 27, 2008).

In summary, several considerations are recognized as important to judgments on the public welfare significance of the array of effects of different O_3 exposure conditions on vegetation. While there are complexities associated with the consideration of the magnitude of key vegetation effects that might be concluded to be adverse to ecosystems and associated services, there are numerous locations where O_3-sensitive tree species are present that may be vulnerable to impacts from O_3 on tree growth, productivity and carbon storage and their associated ecosystems and services. Cumulative exposures that may elicit effects and the significance of the effects in specific situations can vary due to differences in exposed species sensitivity, the importance of the observed or predicted O_3-induced effect, the role that the species plays in the ecosystem, the intended use of the affected species and its associated ecosystem and services, the presence of other co-occurring predisposing or mitigating factors, and associated uncertainties and limitations. These factors contribute to the complexity of the Administrator's judgments regarding the adversity of known and anticipated effects to the public welfare.

B. Need for Revision of the Secondary Standard

The initial issue to be addressed in this review of the secondary standard for O_3 is whether, in view of the currently available scientific evidence, exposure and risk information and air quality analyses, as reflected in the record, the standard should be retained or revised. In drawing conclusions on adequacy of the current O_3 secondary standard, the Administrator has taken into account both evidence-based and quantitative exposure- and risk-based considerations, as well as advice from CASAC and public comment. Evidence-based considerations draw upon the EPA's assessment and integrated synthesis of the scientific evidence from experimental and field studies evaluating welfare effects related to O_3 exposure, with a focus on policy-relevant considerations, as discussed in the PA. Air quality analyses inform these considerations with regard to cumulative, seasonal exposures occurring in areas of the U.S. that meet the current standard. Exposure- and risk-based considerations draw upon the EPA assessments of risk of key welfare effects, including O_3 effects on forest growth, productivity, carbon storage, crop yield and visible foliar injury, expected to occur in model-based scenarios for the current standard, with appropriate consideration of associated uncertainties.

In evaluating whether it is appropriate to revise the current standard, the Administrator's considerations build on the general approach used in the last review, as summarized in section IV.A of the proposal, and reflect the body of evidence and information available during this review. The approach used is based on an integration of the information on vegetation effects associated with exposure to O_3 in ambient air, as well as policy judgments on the adversity of such effects to public welfare and on when the standard is requisite to protect public welfare from known or anticipated adverse effects. Such judgments are informed by air quality and related analyses, quantitative assessments, when available, and qualitative assessment of impacts that could not be quantified. The Administrator has taken into

[185] See *http://www2.nature.nps.gov/air/Pubs/pdf/flag/NPSozonesensppFLAG06.pdf.*

[186] Basal area for resident species in national forests and parks are available in files accessible at: *http://www.fs.fed.us/foresthealth/technology/nidrm2012.shtml.* Basal area is generally described as the area of ground covered by trees.

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account both evidence of effects on vegetation and ecosystems and public uses of these entities that may be important to the public welfare. The decision on adequacy of the protection provided by the current standard has also considered the 2013 remand of the secondary standard by the D.C. Circuit such that this decision incorporates the EPA's response to this remand.

Section IV.B.1 below summarizes the basis for the proposed decision by the Administrator that the current secondary standard should be revised. Significant comments received from the public on the proposal are discussed in section IV.B.2 and the Administrator's final decision is described in section IV.B.3.

1. Basis for Proposed Decision

In evaluating whether it was appropriate to propose to retain or revise the current standard, as discussed in section IV.D of the proposal, the Administrator carefully considered the assessment of the current evidence in the ISA, findings of the WREA, including associated limitations and uncertainties, considerations and staff conclusions and associated rationales presented in the PA, views expressed by CASAC, and public comments that had been offered up to that point. In the paragraphs below, we summarize the proposal presentation of the PA considerations with regard to adequacy of the current secondary standard, advice from the CASAC, and the Administrator's proposed conclusions, drawing from section IV.D of the proposal, where a fuller discussion is presented.

a. Considerations and Conclusions in the PA

The PA evaluation is based on the longstanding evidence for O_3 effects and the associated conclusions in the current review of causal and likely causal relationships between O_3 in ambient air and an array of welfare effects at a range of biological and ecological scales of organization, as summarized in section IV.A.1 above (and described in detail in the ISA). Drawing from the ISA and CASAC advice, the PA emphasizes the strong support in the evidence for the conclusion that effects on vegetation are attributable to cumulative seasonal O_3 exposures, taking note of the improved ''explanatory power'' (for effects on vegetation) of the W126 index over other exposure metrics, as summarized in section IV.A.1.c above. The PA further recognizes the strong basis in the evidence for the conclusion that it is appropriate to use a cumulative seasonal exposure metric, such as the W126 index, to judge impacts of O_3 on vegetation; related effects on ecosystems and services, such as carbon storage; and the level of public welfare protection achieved for such effects (U.S. EPA, 2014c, p. 5–78). As a result, based on the strong support in the evidence and advice from CASAC in the current and past reviews, the PA concludes that the most appropriate and biologically relevant way to relate O_3 exposure to plant growth, and to determine what would be adequate protection for public welfare effects attributable to the presence of O_3 in ambient air, is to characterize exposures in terms of a cumulative seasonal form, and in particular the W126 metric (U.S. EPA, 2014c, pp. 5–7 and 5–78). Accordingly, in considering the evidence with regard to level of protection provided by the current secondary standard, the PA considers air quality data and exposure-response relationships for vegetation effects, particularly those related to forest tree growth, productivity and carbon storage, in terms of the W126 index (U.S. EPA, 2014c, section 5.2; 79 FR 75330–75333, December 17, 2014).

In considering the extent to which such growth-related effects might be expected to occur under conditions that meet the current secondary standard, the PA focused particularly on tree seedling RBL estimates for the 11 species for which robust E–R functions have been developed, noting the CASAC concurrence with use of O_3-related tree biomass loss as a surrogate for related effects extending to the ecosystem scale (U.S. EPA, 2014c, p. 5–80, Frey, 2014c, p. 10). The PA evaluation relied on RBL estimates for these 11 species derived using the robust OTC-based E–R functions, noting that analyses newly performed in this review have reduced the uncertainty associated with using OTC E–R functions to predict tree growth effects in the field (U.S. EPA, 2014c, section 5.2.1; U.S. EPA, 2013, section 9.6.3.2).

In considering the RBL estimates for different O_3 conditions associated with the current standard, the PA focused primarily on the median of the species-specific (composite) E–R functions. In so doing, in the context of considering the adequacy of protection afforded by the current standard, the PA takes note of CASAC's view regarding a 6% median RBL (Frey, 2014c, p. 12). Based on the summary of RBL estimates in the PA, the PA notes that the median species RBL estimate, across the 11 estimates derived from the robust species-specific E–R functions, is at or above 6% for W126 index values of 19 ppm-hrs and higher (U.S. EPA, 2014c, Tables 6–1 and 5C–3).

In recognition of the potential significance to public welfare of vegetation effects in Class I areas, the proposal described in detail findings of the PA analysis of the occurrence of O_3 concentrations associated with the potential for RBL estimates above benchmarks of interest in Class I areas that meet the current standard, focusing on 22 Class I areas for which air quality data indicated the current standard was met and cumulative seasonal exposures, in terms of a 3-year average W126 index, were at or above 15 ppm-hrs (79 FR 75331–75332, Table 7, December 17, 2014; U.S. EPA, 2014c, Table 5–2). The PA noted that W126 index values (both annual and 3-year average values) in many such areas, distributed across multiple states and NOAA climatic regions, were above 19 ppm-hrs. The highest 3-year average value was over 22 ppm-hrs and the highest annual value was over 27 ppm-hrs, exposure values for which the corresponding median species RBL estimates markedly exceed 6%, which CASAC has termed ''unacceptably high'' (U.S. EPA, 2014c, section 5.2). The PA additionally considered the species-specific RBL estimates for two tree species (quaking aspen and ponderosa pine) that are found in many of these Class I areas and that have a sensitivity to O_3 exposure that places them slightly more sensitive than the median of the group for which robust E–R functions have been established (U.S. EPA, 2014c, sections 5.2 and 5.7). As further summarized in the proposal, the PA describes the results of this analysis, particularly in light of advice from CASAC regarding the significance of the 6% RBL benchmark, as evidence of the occurrence in Class I areas, during periods when the current standard is met, of cumulative seasonal O_3 exposures of a magnitude for which the tree growth impacts indicated by the associated RBL estimates might reasonably be concluded to be important to public welfare (79 FR 75332; U.S. EPA, 2014c, sections 5.2.1 and 5.7).

The proposal also noted that the PA additionally considered findings of the WREA analyses of O_3 effects on tree growth and an array of ecosystem services provided by forests, including timber production, carbon storage and air pollution removal (79 FR 75332–75333; U.S. EPA, 2014b, sections 6.2–6.8; U.S. EPA, 2014c, section 5.2). While recognizing that these analyses provide quantitative estimates of impacts on tree growth and associated services for several different air quality scenarios,

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the PA takes note of the large uncertainties associated with these analyses (see U.S. EPA, 2014b, Table 6–27) and the potential for these findings to underestimate the response at the national scale. While noting the potential usefulness of considering predicted and anticipated impacts to these services in assessing the extent to which the current information supports or calls into question the adequacy of the protection afforded by the current standard, the PA also recognizes significant uncertainties associated with the absolute magnitude of the estimates for these ecosystem service endpoints which limited the weight staff placed on these results (U.S. EPA, 2014c, sections 5.2 and 5.7).

As described in the proposal, the PA also considered O_3 effects on crops, taking note of the extensive and long-standing evidence of the detrimental effect of O_3 on crop production, which continues to be confirmed by evidence newly available in this review (79 FR 75333; U.S. 2014c, sections 5.3 and 5.7). With regard to consideration of the quantitative impacts of O_3 exposures under exposure conditions associated with the current standard, the PA focused on RYL estimates that had strong support in the current evidence (as characterized in the ISA, section 9.6) in light of CASAC comments regarding RYL benchmarks (Frey, 2014c, pp. iii and 14). In considering such evidence-based analyses, as well as the exposure/risk-based information for crops, the PA notes the CASAC comments regarding the use of crop yields as a surrogate for consideration of public welfare impacts, which noted that ''[c]rops provide food and fiber services to humans'' and that ''[e]valuation of market-based welfare effects of O_3 exposure in forestry and agricultural sectors is an appropriate approach to take into account damage that is adverse to public welfare'' (Frey, 2014c, p. 10; U.S. EPA, 2014c, section 5.7). The PA additionally notes, however, as recognized in section IV.A.3 above that the determination of the point at which O_3-induced crop yield loss becomes adverse to the public welfare is still unclear, given that crops are heavily managed (*e.g.,* with fertilizer, irrigation) for optimum yields, have their own associated markets and that benefits can be unevenly distributed between producers and consumers (79 FR 75322; U.S. EPA, 2014c, sections 5.3 and 5.7).

With regard to visible foliar injury, as summarized in the proposal, the PA recognizes the long-standing evidence that has established that O_3 causes diagnostic visible foliar injury symptoms on studied bioindicator species and also recognizes that such O_3-induced impacts have the potential to impact the public welfare in scenic and/or recreational areas, with visible foliar injury associated with important cultural and recreational ecosystem services to the public, such as scenic viewing, wildlife watching, hiking, and camping, that are of significance to the public welfare and enjoyed by millions of Americans every year, generating millions of dollars in economic value (U.S. EPA, 2014b, section 7.1). In addition, several tribes have indicated that many of the O_3-sensitive species (including bioindicator species) are culturally significant (U.S. EPA, 2014c, Table 5–1). Similarly, the PA notes CASAC comments that ''visible foliar injury can impact public welfare by damaging or impairing the intended use or service of a resource,'' including through ''visible damage to ornamental or leafy crops that affects their economic value, yield, or usability; visible damage to plants with special cultural significance; and visible damage to species occurring in natural settings valued for scenic beauty or recreational appeal'' (Frey, 2014c, p. 10). Given the above, and taking note of CASAC views, the PA recognizes visible foliar injury as an important O_3 effect which, depending on severity and spatial extent, may reasonably be concluded to be of public welfare significance, especially when occurring in nationally protected areas, such as national parks and other Class I areas.

As summarized in the proposal, the PA additionally takes note of the evidence described in the ISA regarding the role of soil moisture conditions that can decrease the incidence and severity of visible foliar injury under dry conditions (U.S. EPA, 2014c, sections 5.4 and 5.7). As recognized in the PA, this area of uncertainty complicates characterization of the potential for visible foliar injury and its severity or extent of occurrence for given air quality conditions and thus complicates identification of air quality conditions that might be expected to provide a specific level of protection from this effect (U.S. EPA, 2014c, sections 5.4 and 5.7). While noting the uncertainties associated with describing the potential for visible foliar injury and its severity or extent of occurrence for any given air quality conditions, the PA notes the occurrence of O_3-induced visible foliar injury in areas, including federally protected Class I areas that meet the current standard, and suggests it may be appropriate to consider revising the standard for greater protection. In so doing, however, the PA recognizes that the degree to which O_3-induced visible foliar injury would be judged important and potentially adverse to public welfare is uncertain (U.S. EPA, 2014c, section 5.7).

As noted in the proposal, with regard to other welfare effects, for which the ISA determined a causal or likely causal relationships with O_3 in ambient air, such as alteration of ecosystem water cycling and changes in climate, the PA concludes there are limitations in the available information that affect our ability to consider potential impacts of air quality conditions associated with the current standard.

Based on the considerations described in the PA, summarized in the proposal and outlined here, the PA concludes that the currently available evidence and exposure/risk information call into question the adequacy of the public welfare protection provided by the current standard and provide support for considering potential alternative standards to provide increased public welfare protection, especially for sensitive vegetation and ecosystems in federally protected Class I and similarly protected areas. In this conclusion, staff gives particular weight to the evidence indicating the occurrence in Class I areas that meet the current standard of cumulative seasonal O_3 exposures associated with estimates of tree growth impacts of a magnitude that may reasonably be considered important to public welfare.

b. CASAC Advice

The proposal also summarized advice offered by the CASAC in the current review, based on the updated scientific and technical record since the 2008 rulemaking. The CASAC stated that it ''[supports] the conclusion in the Second Draft PA that the current secondary standard is not adequate to protect against current and anticipated welfare effects of ozone on vegetation'' (Frey, 2014c, p. iii) and that the PA ''clearly demonstrates that ozone-induced injury may occur in areas that meet the current standard'' (Frey, 2014c, p. 12). The CASAC further stated ''[w]e support the EPA's continued emphasis on Class I and other protected areas'' (Frey, 2014c, p. 9). Additionally, the CASAC indicated support for the concept of ecosystem services ''as part of the scope of characterizing damage that is adverse to public welfare'' and ''concur[red] that trees are important from a public welfare perspective because they provide valued services to humans, including aesthetic value, food, fiber, timber, other forest products, habitat, recreational opportunities, climate regulation, erosion control, air pollution removal, and hydrologic and fire regime stabilization'' (Frey, 2014c, p. 9). Similar to comments from CASAC in the last review, and comments on the proposed reconsideration, the current CASAC also endorsed the PA discussions and conclusions on biologically relevant exposure metrics and the focus on the W126 index accumulated over a 12-hour period (8 a.m.–8 p.m.) over the 3-month summation period of a year resulting in the maximum value (Frey, 2014c, p. iii).

In addition, CASAC stated that ''relative biomass loss for tree species, crop yield loss, and visible foliar injury are appropriate surrogates for a wide range of damage that is adverse to public welfare,'' listing an array of related ecosystem services (Frey, 2014c, p. 10). With respect to RBL for tree species, CASAC states that it is appropriate to identify in the PA ''a range of levels of alternative W126-based standards that include levels that aim for not greater than 2% RBL for the median tree species'' and that a median tree species RBL of 6% is ''unacceptably high'' (Frey, 2014c, pp. 13 and 14). With respect to crop yield loss, CASAC points to a benchmark of 5%, stating that a crop RYL for median species over 5% is ''unacceptably high'' and described crop yield as a surrogate for related services (Frey, 2014c, p. 13).

c. Administrator's Proposed Conclusions

At the time of proposal, the Administrator took into account the information available in the current review with regard to the nature of O_3-related effects on vegetation and the adequacy of protection provided by the current secondary standard. The Administrator recognized the appropriateness and usefulness of the W126 metric in evaluating O_3 exposures of potential concern for vegetation effects, additionally noting support conveyed by CASAC for such a use for this metric. Further, the Administrator took particular note of (1) the PA analysis of the magnitude of tree seedling growth effects (biomass loss) estimated for different cumulative, seasonal, concentration-weighted exposures in terms of the W126 metric; (2) the monitoring analysis in the PA of cumulative exposures (in terms of W126 index) occurring in locations where the current standard is met, including those locations in or near Class I areas, and associated estimates of tree seedling growth effects; and (3) the analyses in the WREA illustrating the geographic distribution of tree species for which E–R functions are available and estimates of O_3-related growth impacts for different air quality scenarios, taking into account the identified potential for the WREA's existing standard scenario to underestimate the highest W126-based O_3 values that would be expected to occur.

With regard to considering the adequacy of public welfare protection provided by the current secondary standard at the time of proposal, the Administrator focused first on welfare effects related to reduced native plant growth and productivity in terrestrial systems, taking note of the following: (a) The ISA conclusion of a causal relationship between O_3 in the ambient air and these welfare effects, and supporting evidence related to O_3 effects on vegetation growth and productivity, including the evidence from OTC studies of tree seedling growth that support robust E–R functions for 11 species; (b) the evidence, described in section IV.D.1 of the proposal and summarized above, of the occurrence of cumulative seasonal O_3 exposures for which median species RBL estimates are of a magnitude that CASAC has termed ''unacceptably high'' in Class I areas during periods where the current standard is met; (c) actions taken by Congress to establish public lands that are set aside for specific uses intended to provide benefits to the public welfare, including lands that are to be protected so as to conserve the scenic value and the natural vegetation and wildlife within such areas for the enjoyment of future generations, such as national parks and forests, wildlife refuges, and wilderness areas (many of which have been designated Class I areas); and (d) PA conclusions that the current information calls into question the adequacy of the current standard, based particularly on impacts on tree growth (and the potential for associated ecosystem effects), estimated for Class I area conditions meeting the current standard, that are reasonably concluded to be important from a public welfare standpoint in terms of both the magnitude of the vegetation effects and the significance to public welfare of such effects in such areas.

At the time of proposal, the Administrator also recognized the causal relationships between O_3 in the ambient air and visible foliar injury, reduced yield and quality of agricultural crops, and alteration of below-ground biogeochemical cycles associated with effects on growth and productivity. As to visible foliar injury, she took note of the complexities and limitations in the evidence base regarding characterizing air quality conditions with respect to the magnitude and extent of risk for visible foliar injury, and she additionally recognized the challenges of associated judgments with regard to adversity of such effects to public welfare. In taking note of the conclusions with regard to crops, she recognized the complexity of considering adverse O_3 impacts to public welfare due to the heavy management common for achieving optimum yields and market factors that influence associated services and additionally took note of the PA conclusions that placing emphasis on the protection afforded to trees inherently also recognizes a level of protection afforded for crops.

Based on her consideration of the conclusions in the PA, and with particular weight given to PA findings pertaining to tree growth-related effects, as well as with consideration of CASAC's conclusion that the current standard is not adequate, the Administrator proposed to conclude that the current standard is not requisite to protect public welfare from known or anticipated adverse effects and that revision is needed to provide the requisite public welfare protection, especially for sensitive vegetation and ecosystems in federally protected Class I areas and in other areas providing similar public welfare benefits. The Administrator further concluded that the scientific evidence and quantitative analyses on tree growth-related effects provide strong support for consideration of alternative standards that would provide increased public welfare protection beyond that afforded by the current O_3 secondary standard. She further noted that a revised standard would provide increased protection for other growth-related effects, including for carbon storage and for areas for which it is more difficult to determine public welfare significance, as recognized in section IV.B.2 of the proposal, as well as other welfare effects of O_3, including visible foliar injury and crop yield loss.

2. Comments on the Need for Revision In

considering comments on the need for revision, we first note the advice and recommendations from CASAC with regard to the adequacy of the current standard. In its review of the second draft PA, CASAC stated that it ''supports the scientific conclusion in the Second Draft PA that the current secondary standard is not adequate to protect against current and anticipated welfare effects of ozone on vegetation'' (Frey, 2014c).

General comments received from the public on the proposal that are based on relevant factors and either supported or opposed the proposed decision to revise

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the current O_3 secondary standard are addressed in this section. Comments on specific issues or information that relate to consideration of the appropriate elements of a revised secondary standard are addressed below in section IV.C. Other specific comments related to standard setting, as well as general comments based on implementation-related factors that are not a permissible basis for considering the need to revise the current standard, are addressed in the Response to Comments document.

Public comments on the proposal were divided with regard to support for the Administrator's proposed decision to revise the current secondary standard. Many state and local environmental agencies or government bodies, tribal agencies and organizations, and environmental organizations agreed with the EPA's proposed conclusion on the need to revise the current standard, stating that the available scientific information shows that O_3-induced vegetation and ecosystem effects are occurring under air quality conditions allowed by the current standard and, therefore, provides a strong basis and support for the conclusion that the current secondary standard is not adequate. In support of their view, these commenters relied on the entire body of evidence available for consideration in this review, including evidence assessed previously in the 2008 review. These commenters variously pointed to the information and analyses in the PA and the conclusions and recommendations of CASAC as providing a clear basis for concluding that the current standard does not provide adequate protection of public welfare from O_3-related effects. Many of these commenters generally noted their agreement with the rationale provided in the proposal with regard to the Administrator's proposed conclusion on adequacy of the current standard, and some gave additional emphasis to several aspects of that rationale, including the appropriateness of the EPA's attention to sensitive vegetation and ecosystems in Class I areas and other public lands that provide similar public welfare benefits and of the EPA's reliance on the strong evidence of impacts to tree growth and growth-related effects.

Comments from tribal organizations additionally noted that many Class I areas are of sacred value to tribes or provide treaty-protected benefits to tribes, including the exercise of gathering rights. Tribal organizations also noted the presence in Class I areas of large numbers of culturally important plant species, which they indicate to be impacted by air quality conditions allowed by the current standard. The impacts described include visible foliar injury, loss in forest growth and crop yield loss, which these groups describe as especially concerning when occurring on lands set aside for the benefit of the public or that are of sacred value to tribes or provide treaty-protected benefits to tribes.

As described in section IV.B.3 below, the EPA generally agrees with the view of these commenters regarding the need for revision of the current secondary standard and with CASAC that the evidence provides support for the conclusions that the current secondary standard is not adequate to protect public welfare from known or anticipated adverse effects, particularly with respect to effects on vegetation.

A number of industries, industry associations, or industry consultants, as well as some state governors, attorneys general and environmental agencies, disagreed with the EPA's proposed conclusion on the adequacy of the current standard and recommended against revision. In support of their position, these commenters variously stated that the available evidence is little changed from that available at the time of the 2008 decision, and that the evidence is too uncertain, including with regard to growth-related effects and visible foliar injury, to support revision, and does not demonstrate adverse effects to public welfare for conditions associated with the current standard, with some commenters stating particularly that the EPA analysis of Class I areas did not document adverse effects to public welfare. They also cited the WREA modeling analyses as indicating that any welfare improvements associated with a revised standard would be marginal; in particular, compared to the benefits of achieving the current standard. Further, they state that, because of long-range transport of O_3 and precursors, it is not appropriate for the EPA to draw conclusions about the level of protection offered by the current standard based on current air quality conditions; in support of this view, these commenters point to different modeling analyses as demonstrating that under conditions where the current standard is met throughout the U.S., the associated W126 values would all be below the upper end of the range proposed as providing requisite public welfare protection and nearly all below the lower end of 13 ppm-hrs.

As an initial matter, we note that, as noted in sections I.C and IV.A above, the EPA's 2008 decision on the secondary standard was remanded back to the Agency because in setting the 2008 secondary standard, the EPA failed to specify what level of air quality was requisite to protect public welfare from known or anticipated adverse effects or explain why any such level would be requisite. So, in addressing the court remand, the EPA has more explicitly considered the extent to which protection is provided from known or anticipated effects that the Administrator may judge to be adverse to public welfare, and has described how the air quality associated with the revised standard would provide requisite public welfare protection, consistent with CAA section 109(b)(2) and the court's decision remanding the 2008 secondary standard. In undertaking this review, consistent with the direction of the CAA, the EPA has considered the current air quality criteria.

While we recognize, as stated in the proposal, that the evidence newly available in this review is largely consistent with the evidence available at the time of the last review (completed in 2008) with regard to the welfare effects of O_3, we disagree with the commenters' interpretations of the evidence and analyses available in this review and with their views on the associated uncertainties. As summarized in section IV.A above, the ISA has determined causal relationships to exist between several vegetation and ecosystem endpoints and O_3 in ambient air (U.S. 2013, section 9.7). The ISA characterized the newly available evidence as largely consistent with and supportive of prior conclusions, as summarized in section IV.A above. This is not to say, however, that there is no newly available evidence and information in this review or that it is identical to that available in the last review. In some respects, the newly available evidence has strengthened the evidence available in the last review and reduced important uncertainties. As summarized in section IV.A.1.b above, newly available field studies confirm the cumulative effects and effects on forest community composition over multiple seasons. Additionally, among the newly available evidence for this review are analyses documented in the ISA that evaluate the RBL and RYL E–R functions for aspen and soybean, respectively, with experimental datasets that were not used in the derivation of the functions (U.S. 2013, section 9.6.3). These evaluations confirm the pertinence of the tree seedling RBL estimates for aspen, a species with sensitivity roughly midway in the range of sensitivities for the studied species, across multiple years in older trees.

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With regard to crops, the ISA evaluations demonstrate a robustness of the E–R functions to predict O_3-attributable RYL and confirm the relevance of the crop RYL estimates for more recent cultivars currently growing in the field. Together, the information newly available in this review confirms the basis for the E–R functions and strengthens our confidence in interpretations drawn from their use in other analyses newly available in this review that have been described in the WREA and PA.

With regard to comments on uncertainties associated with estimates of RBL, we first note that these established, robust E–R functions, which the EPA gave particular emphasis in this review, are available for seedling growth for 11 tree species native to the U.S., as summarized in section IV.A.1.b above and described in the proposal. These E–R functions are based on studies of multiple genotypes of 11 tree species grown for up to three years in multiple locations across the U.S. (U.S. EPA, 2013, section 9.6.1). We have recognized the uncertainty regarding the extent to which the studied species encompass the O_3 sensitive species in the U.S. and also the extent to which they represent U.S. vegetation as a whole (U.S. EPA, 2014b, section 6.9). However, the studied species include both deciduous and coniferous trees with a wide range of sensitivities and species native to every region across the U.S. and in most cases are resident across multiple states and NOAA climatic regions (U.S. EPA, 2014b, Appendix 6A). While the CASAC stated that there is ''considerable uncertainty in extrapolating from the [studied] forest tree species to all forest tree species in the U.S.,'' it additionally expressed the view that it should be anticipated that there are highly sensitive vegetation species for which we do not have E–R functions and others that are insensitive.[187] In so doing, the CASAC stated that it ''should not be assumed that species of unknown sensitivity are tolerant to ozone'' and ''[i]t is more appropriate to assume that the sensitivity of species without E–R functions might be similar to the range of sensitivity for those species with E–R functions'' (Frey, 2014c, p. 11). Accordingly, we disagree with commenters' view that effects on these species are not appropriate considerations for evaluation of the adequacy of the current standard.

In support of their view that RBL estimates are too uncertain to inform a conclusion that the current standard is not adequately protective of public welfare, some commenters state that some of the 11 E–R functions are based on as few as one study. The EPA agrees that there are two species for which there is only one study supporting the E–R function (Virginia pine and red maple). We also note, however, that those two species are appreciably less sensitive than the median (Lee and Hogsett, 1996; U.S. EPA, 2014c, Table 5C–1). Thus, in the relevant analyses, they tend to influence the median toward a relatively less (rather than more) sensitive response. Further, there are four species for which the E–R functions are based on more than five studies,[188] contrary to the commenters' claims of there being no functions supported by that many studies. That said, the EPA has noted the relatively greater uncertainty in the species for which fewer studies are available, and it is in consideration of such uncertainties that the EPA focused in the proposal on the median E–R function across the 11 species, rather than a function for a species much more (or less) sensitive than the median. The EPA additionally notes that it gave less emphasis to the E–R function available for one species, eastern cottonwood, based on CASAC advice that the study results supporting that E–R function were not as strong as the results of the other experiments that support the other, robust E–R functions and that the eastern cottonwood study results showed extreme sensitivity to O_3 compared to other studies (Frey, 2014c, p. 10). Accordingly, the EPA has appropriately considered the strength of the scientific evidence and the associated uncertainties in considering revision of the secondary standard.

Other commenters stated that the scientific evidence does not support revising the NAAQS, pointing to uncertainty related to interpretation of the RBL estimates (based on tree seedling studies) with regard to effects on older tree lifestages. Some of these commenters' claim that mature canopy trees experience reduced O_3 effects. The EPA agrees that the quantitative information for O_3 growth effects on older tree lifestages is available for a more limited set of species than that available for tree seedlings. We note, however, that this is an area for which there is information newly available in this review. A detailed analysis of study data for seedlings and older lifestages of aspen shows close agreement between the O_3-attributable reduced growth observed in the older trees and reductions predicted from the seedling E–R function (U.S. EPA, 2013, section 9.6.3.2; discussed in the PA, section 5.2.1 as noted in the proposal, p. 75330). This finding, newly available in this review and documenting impacts on mature trees, improves our confidence in conclusions drawn with regard to the significance of RBL estimates for this species, which is prevalent across multiple regions of the U.S.[189] It is also noteworthy that this species is generally more sensitive to O_3 effects on growth than the median of the 11 species with robust E–R functions (as shown in U.S. EPA 2014c, Table 5C–1). Other newly available studies, summarized in section IV.A.1.b above and section IV.B.1.b of the proposal, provide additional evidence of O_3 impacts on mature trees, including a meta-analysis reporting older trees to be more affected by O_3 than younger trees (U.S. EPA, 2013, p. 9–42; Wittig et al., 2007). We additionally note that CASAC ''concur[red] that biomass loss in trees is a relevant surrogate for damage to tree growth that affects ecosystem services such as habitat provision for wildlife, carbon storage, provision of food and fiber, and pollution removal'' additionally stating that ''[b]iomass loss may also have indirect process-related effects such as on nutrient and hydrologic cycles'' leading them to conclude that ''[t]herefore, biomass loss is a scientifically valid surrogate of a variety of adverse effects to public welfare'' (Frey, 2014c, p. 10).

As noted in section IV.A above and discussed below, the Administrator's final decision on the adequacy of the current standard draws upon, among other things, the available evidence and quantitative analyses as well as judgments about the appropriate weight to place on the range of uncertainties inherent in the evidence and analyses. The strengthening in this review, as compared with the last review, of the basis for the robust E–R functions for tree seedling RBL, as well as other newly available quantitative analyses,

[187] Use of RBL estimates in the proposal, and in this final decision, focuses on the RBL for the studied species as a surrogate for a broad array of growth-related effects of potential public welfare significance, consistent with the CASAC advice.

[188] These four species, aspen, Douglas fir, ponderosa pine and red alder, range broadly in sensitivities that fall above, below and at the median for the 11 species (Lee and Hogsett, 1996; U.S. EPA, 2014c, Table 5C–1).

[189] The WREA notes a few additional, limited analyses using modeling tools and data from previous publications that indicate there may be species-specific differences in the extent of similarities between seedling and adult growth response to O_3, with some species showing greater and some lesser response for seedlings as compared to mature tree, but a general comparability (U.S. EPA 2014b, section 6.2.1.1 and p. 6–67).

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will, accordingly, contribute to judgments made by the Administrator with regard to these effects in reaching her final decisions in this review.

Amongst the newly available information in this review is a new analysis describing W126-based exposures occurring in counties containing Class I areas for which monitoring data indicated compliance with the current standard. The PA gave particular attention to this analysis in consideration of the adequacy of the current standard, and this analysis was also described in the proposal (U.S. EPA, 2014c, Appendix 5B and pp. 5–27 to 5–29; 79 FR 75331–75332, December 17, 2014). Some of the commenters who disagreed with the EPA's conclusion on adequacy of the current standard variously stated that this analysis does not demonstrate growth effects are occurring in Class I areas and that the analysis is too uncertain for reliance on by the Administrator in her judgment on adequacy of the current standard. While the EPA agrees with commenters that data on the occurrence of growth effects in the areas and time periods identified are not part of this analysis, we note that this is because such data have not been collected and consequently cannot be included. As a result, the EPA has utilized measurements of O_3 in or near these areas in combination with the established E–R functions to estimate the potential for growth impacts in these areas under conditions where the current standard is met. The EPA additionally notes that species for which E–R functions have been developed have been documented to occur within these areas (see Table 3).

The EPA disagrees with commenters regarding the appropriateness of this analysis for the Administrator's consideration. This analysis documents the occurrence of cumulative growing season exposures in these ecosystems which the EPA and CASAC have interpreted, through the use of the established E–R functions for tree seedling growth effects summarized in section IV.A.1.b above (and described in the ISA, PA and proposal), as indicating the potential for growth effects of significance in these protected areas. To the extent that these comments imply that the Administrator may only consider welfare effects that are certain in judging the adequacy of the current standard, we note that section 109(b)(2) of the CAA plainly provides for consideration of both known and anticipated adverse effects in establishing or revising secondary NAAQS.

In support of some commenters' view that this analysis is too uncertain to provide a basis for the Administrator's proposed conclusion that the current standard is not adequate, one commenter observed that the O_3 monitors used for six of the 22 Class I areas in the analysis, although in the same county, were sited outside of the Class I areas. This was the case due to the analysis being focused on the highest monitor in the county that met the current standard. To clarify the presentation, however, we have refocused the presentation, restricting it to data for monitors sited in or within 15 kilometers of a Class I area,[190] and note that the results are little changed, continuing to call into question the adequacy of the current standard. As shown in Table 3, the dataset in the refocused presentation, which now spans 1998 up through 2013, includes 17 Class I areas for which monitors were identified in this manner. For context, we note that this represents nearly a quarter of the Class I areas for which there are O_3 monitors within 15 km.[191]

In recognition of the influence that other environmental factors can exert in the natural environment on the relationship between ambient O_3 exposures and RBL, potentially modifying the impact predicted by the E–R functions, the PA and proposal took particular note of the occurrence of 3-year average W126 index values at or above 19 ppm-hrs. In the re-focused analysis in Table 3, there are 11 areas, distributed across four states in two NOAA climatic regions, for which the 3-year W126 exposure index values ranged at or above 19 ppm-hrs, a value for which the corresponding median species RBL estimate for a growing season's exposure is 6%, a magnitude termed ''unacceptably high'' by CASAC (Frey, 2014c, p. 13). The highest 3-year W126 index values in these 11 areas ranged from 19.0 up to 22.2 ppm-hrs, a cumulative seasonal exposure for which the median species RBL estimate is 9% for a single growing season. The annual W126 index values range above 19 ppm-hrs in 15 of the areas in the re-focused table provided here; these areas are distributed across six states (AZ, CA, CO, KY, SD, UT) and four regions (West, Southwest, West North Central and Central).[192] The highest index values in the areas with annual index values above 19 ppm-hrs range from 19.1 to 26.9 ppm-hrs. As is to be expected from the focus on a smaller dataset, the number of states with 1-year W126 index values above 19 ppm-hrs is smaller in the refocused analysis (15 as compared to 20), although the number of regions affected is the same. More importantly, however, the number of areas with 3-year W126 index values at or above 19 ppm-hrs is the same, 11 Class I areas across two regions, supporting the prior conclusions.

TABLE 3—O_3 CONCENTRATIONS FOR CLASS I AREAS DURING PERIOD FROM 1998 TO 2013 THAT MET THE CURRENT STANDARD AND WHERE 3-YEAR AVERAGE W126 INDEX VALUE WAS AT OR ABOVE 15 ppm-hrs

Class I area (distance away, if monitor is not at/within boundaries)	State/County	Design value (ppb)*	3-Year average W126 (ppm-hrs)* (# ≥ 19 ppm-hrs, range)	Annual W126 (ppm-hrs)* (# ≥ 19 ppm-hrs, range)	Number of 3-year periods
Bridger Wilderness Area [QA, DF] (8.9 km).	WY/Sublette	70–72	16.2–17.0	13.9–18.8	4
Canyonlands National Park [QA, DF, PP].	UT/San Juan	70–73	15.4–19.5 (2, 19.1–19.5)	9.6–23.6 (4, 19.2–23.6)	8
Chiricahua National Monument [DF, PP] (12 km).	AZ/Cochise	69–73	15.2–19.8 (1, 19.8)	11.7–21.9 (2, 19.8–21.9)	10
Grand Canyon National Park [QA, DF, PP].	AZ/Coconino	68–74	15.3–22.2 (7, 19.1–22.2)	10.1–26.9 (6, 19.8–26.9)	12
Desolation Wilderness [PP] (3.9 km)	CA/El Dorado	75	19.8 (1, 19.8)	15.6–22.9 (2, 21.0–22.9)	1

[190] The 15 km distance was selected as a natural breakpoint in distance of O_3 monitoring sites from Class I areas and as still providing similar surroundings to those occurring in the Class I area. We note that given the strict restrictions on structures and access within some of these areas, it is common for monitors intended to collect data pertaining to air quality in these types of areas to be sited outside their boundaries.

[191] There is an O_3 monitor within fewer than 15% of all Class I areas, and fewer than half of all Class I areas have a monitor within 15 km.

[192] This compares to 20 areas in eight states and four regions in the earlier analysis.

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TABLE 3—O_3 CONCENTRATIONS FOR CLASS I AREAS DURING PERIOD FROM 1998 TO 2013 THAT MET THE CURRENT STANDARD AND WHERE 3-YEAR AVERAGE W126 INDEX VALUE WAS AT OR ABOVE 15 ppm-hrs—Continued

Class I area (distance away, if monitor is not at/within boundaries)	State/County	Design value (ppb)*	3-Year average W126 (ppm-hrs)* (# ≥ 19 ppm-hrs, range)	Annual W126 (ppm-hrs)* (# ≥ 19 ppm-hrs, range)	Number of 3-year periods
Lassen Volcanic National Park [DF, PP].	CA/Shasta	72–74	15.3–15.6	11.5–19.1 (1, 19.1)	2
Mammoth Cave National Park [BC, C, LP, RM, SM, VP, YP] (0.1 km).	KY/Edmonson	74	15.7	12.3–22.0 (1, 22.0)	1
Maroon Bells-Snowmass Wilderness Area [QA, DF] (0.8 km).	CO/Gunnison	68–73	15.6–20.2 (1, 20.2)	13.0–23.8 (3, 21.3–23.8)	8
Mazatzal Wilderness [DF, PP] (10.9 km).	AZ/Maricopa	74–75	17.8–19.9 (1, 19.9)	10.3–26.2 (3, 19.7–26.2)	2
Mesa Verde National Park [DF]	CO/Montezuma	67–73	15.4–20.7 (1, 20.7)	10.7–23.4 (4, 19.5–23.4)	11
Petrified Forest National Park [C]	AZ/Navajo	70	15.4–16.9	12.7–18.6	2
Rocky Mountain National Park [QA, DF, PP] (0.9 km).	CO/Larimer	73–74	15.3–18.4	8.3–26.2 (4, 19.4–26.2)	5
Saguaro National Park [DF, PP] (0.1 km)**.	AZ/Pima	69–74	15.4–19.0 (1, 19.0)	7.3–22.9 (3, 19.6–22.9)	6
	AZ/Gila	72–75	16.6–20.9 (2, 19.0–20.9)	13.8–25.5 (4, 19.0–25.5)	5
Superstition Wilderness Area [PP] (6.3, 14.9 km and 7.2 km)**.	AZ/Maricopa	70–75	15–20.2 (1, 20.2)	6.3–23.9 (4, 19.6–23.9)	4
	AZ/Pinal	72–75	15.3–21.1 (1, 21.1)	10.2–24.7 (4, 21.4–24.7)	7
Weminuche Wilderness Area [QA, DF, PP] (14.9 km).	CO/La Plata	70–74	15.1–19.1 (1, 19.1)	10.8–21.0 (2, 20.8–21.0)	6
Wind Cave National Park [QA, PP]	SD/Custer	70	15.4	12.3–20.5 (1, 20.5)	1
Zion National Park [QA, DF, PP] (3.6 km).	UT/Washington	70–73	17.0–20.1 (2, 19.4–20.1)	14.2–23.2 (3, 19.8–23.2)	6

* Based on hourly O_3 concentration data retrieved from AQS on June 25, 2014, and additional CASTNET data downloaded from *http://java.epa.gov/castnet/epa_jsp/prepackageddata.jsp* on June 25, 2014. Design values shown above are derived in accordance with Appendix P to 40 CFR Part 50. Annual W126 index values are derived as described in section IV.A.1 above; three consecutive year annual values are averaged for 3-year averages. Prior to presentation, both types of W126 index values are rounded to one decimal place. The full list of monitoring site identifiers and individual statistics is available in the docket for this rulemaking.

** No monitor was sited within these Areas and multiple monitors were sited within 15 km. Data for the closest monitor per county are presented.

Superscript letters refer to species present for which E–R functions have been developed. QA=Quaking Aspen, BC=Black Cherry, C=Cottonwood, DF=Douglas Fir, LP=Loblolly Pine, PP=Ponderosa Pine, RM=Red Maple, SM=Sugar Maple, VP=Virginia Pine, YP=Yellow (Tulip) Poplar. Sources include USDA–NRCS (2014, *http://plants.usda.gov*), USDA–FS (2014, *http://www.fs.fed.us/foresthealth/technology/nidrm2012.shtml*) UM–CFCWI (2014, *http://www.wilderness.net/printFactSheet.cfm?WID=583*), NPS (*http://www.nps.gov/pefo/planyourvisit/upload/Common-Plants-Site-Bulletin-sb-2013.pdf*) and Phillips and Comus (2000).

As support for their view that the Class I area analysis is too uncertain to provide a basis for the Administrator's proposed conclusion that the current standard is not adequate, some commenters stated that forests in Class I areas were composed of mature trees and that the tree seedling E–R functions do not predict growth impacts in mature forests. The EPA disagrees with the commenters' statement that Class I areas are only made up of mature trees. Seedlings exist throughout forests as part of the natural process of replacing aging trees and overstory trees affected by periodic disturbances.[193] Seedlings also tend to occur in areas affected by natural disturbances, such as fires, insect infestations and flooding, and such disturbances are common in many natural forests. As noted above, information newly available in this review strengthens our understanding regarding O_3 effects on mature trees for aspen, an important and O_3-sensitive species (U.S. EPA, 2013, section 9.6.3.2).

One commenter additionally stated that the EPA has not shown reduced biomass to be adverse to public welfare, variously citing individual studies, most of which are not considering O_3, as support for their view that such an effect of O_3 may not occur in the environment and may be of no significance if it does. With regard to the occurrence of O_3-related reduced growth in the field, we note the strength of the evidence from field OTC studies on which the E–R functions are based, and evidence from comparative studies with open-air chamberless control treatments suggests that characteristics particular to the OTC did not significantly affect plant response (U.S. EPA, 2013, p. 9–5). Thus, we view the OTC systems as combining aspects of controlled exposure systems with field conditions to facilitate a study providing data that represent the role of the studied pollutant in a natural system.

Further, we disagree with the commenters on the significance of O_3-attributable reduced growth in natural ecosystems. Even in the circumstances cited by the commenter (*e.g.,* subsequent to large-scale disturbances, nutrient limited system, multigeneration exposure), O_3 can affect growth of seedlings and older trees, with the potential for effects on ecosystem productivity, handicapping the sensitive species and affecting community dynamics and associated community composition, as well as ecosystem hydrologic cycles (U.S. EPA, 2013, p. 1–8). For example, two recent studies report on the role of O_3 exposure in affecting water use in a mixed deciduous forest and indicated that O_3 increased water use in the forest and also reduced growth rate (U.S. EPA, 2013, p. 9–43, McLaughlin, 2007a, 2007b). Contrary to the lesser effects implied by the commenters, the authors of these two studies noted implications of their findings with regard to the potential for effects to be amplified under conditions of increased temperature and associated reduced water availability (McLaughlin, 2007a). We additionally note comments from

[193] Basic information on forest processes, including the role of seedlings is available at: *http://www.na.fs.fed.us/stewardship/pubs/NE_forest_regeneration_handbook_revision_130829_desktop.pdf.*

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the CASAC, summarized above, in which it concurs with a focus on biomass loss and the use of RBL estimates, calling biomass loss in trees a ''relevant surrogate for damage to tree growth'' that affects an array of ecosystem services (Frey, 2014c, p. 10), and identifies 6% RBL as ''unacceptably high'' (Frey, 2014c, p. 13). The evidence we presented includes evidence related to RBL estimates above that benchmark. Thus, while we agree that some reductions in tree growth may not be concluded to be adverse to public welfare, we disagree with commenters that we have not presented the evidence, which includes RBL estimates well above the 6% magnitude identified by CASAC, that supports the Administrator's judgments on adversity that may be indicated by such estimates and her conclusion that adequate protection is not provided by the current standard, as described in section IV.B.3 below.

Some commenters disagree with the EPA's consideration of the Class I areas analysis, stating that it is not appropriate for the EPA to evaluate the level of protection offered by the current primary O_3 standard under current conditions due to the long-range transport of O_3 and O_3 precursors to Class I areas from upwind non-attainment areas. It is the view of these commenters that once the upwind areas make emissions reductions to attain the current standard, downwind areas will see improvements in air quality and decreasing W126 levels. In support of this view, commenters point to several modeling analyses. Some commenters point to air quality modeling conducted by an environmental consultant that projects all sites to have W126 index values below 13 ppm-hrs when emissions are adjusted such that all upwind monitors are modeled to meet the current standard. Detailed methodology, results and references for the commenter's modeling analysis were not provided, precluding a thorough evaluation and comparison to the EPA's modeling. While the EPA agrees that transport of O_3 and O_3 precursors can affect downwind monitors, we disagree with commenters regarding the conclusions that are appropriate to draw from modeling simulations for the reasons noted below.

As support for their view that the current standard provides adequate protection, some commenters pointed to estimates drawn from the EPA's air quality modeling performed for the RIA, stating that this modeling for an alternative standard level of 70 ppb indicates ''only a handful'' of monitoring sites approaching as high as 13 ppm-hrs as a 3-year average (*e.g.,* UARG, p. 76). These commenters further point to the WREA modeling, noting that those estimates project that attainment of the current standard would result in only 5 sites above 15 ppm-hrs. Based on these statements, these commenters state that the current standard is likely to provide conditions with no site having a monitor over 17 ppm-hrs and a ''minimal number'' likely exceeding 13 ppm-hrs (*e.g.,* UARG, p. 77). We disagree with commenters' interpretation of the modeling information from the two different assessments. As we summarized in section IV.C.1 of the proposal with regard to the WREA modeling, the modeling estimates are each based on a single set of precursor emissions reductions that are estimated to achieve the desired target conditions, which is also the case for the RIA modeling[194] (U.S. EPA, 2014c, pp. 5–40 to 5–41; see also section 1.2.2 of the 2014 RIA).

As noted in section IV.A.2 above, and in the proposal, the model-adjusted air quality in the WREA scenario for the current standard does not represent an optimized control scenario that just meets the current standard, but rather characterizes one potential distribution of air quality across a region when all monitor locations meet the standard (79 FR 75322; U.S. EPA, 2014b, section 4.3.4.2). Alternate precursor emissions reductions would be expected to produce different patterns of O_3 concentrations and associated differences in W126 index values. Specifically, the precursor emissions reductions scenarios examined in the WREA focuses on regional reductions over broad areas rather than localized cuts that may focus more narrowly on areas violating the current standard (U.S. EPA, 2014b, p. 4–35). The assumption of regionally determined across-the-board emissions reductions is a source of potential uncertainty with the potential to overestimate W126 scenario benefits (U.S. EPA, 2014b, Table 4–5 [row G]). The application of emissions reductions to all locations in each region to bring down the highest monitor in the region to meet the current standard could potentially lead to W126 index underestimates at some locations, as noted in the WREA: ''[w]hile the scenarios implemented in this analysis show that [] bringing down the highest monitor in a region would lead to reductions below the targeted level through the rest of the region, to the extent that the regional reductions from on-the-books controls are supplemented with more local controls the additional benefit may be overestimated'' (U.S. EPA, 2014b, p. 4–36; U.S. EPA, 2014c, pp. 5–40 to 5–41). This point was emphasized by CASAC in their comments on the 2nd draft WREA. CASAC noted that, ''[m]eeting a target level at the highest monitor requires substantial reductions below the targeted level through the rest of the region'' and stated that ''[t]his artificial simulation does not represent an actual control strategy and may conflate differences in control strategies required to meet different standards'' (Frey, 2014b, p. 2).

Due to the uncertainty about what actual future emissions control strategies might be and their associated emissions reductions, and the impact such uncertainty might have on modeling estimates involving reductions from recent conditions, we believe it is important to place weight on ambient air monitoring data for recent conditions in drawing conclusions regarding W126 index values that would be expected in areas that meet the current standard. The analysis of air quality data for Class I areas described in the proposal, and updated in Table 3 above (1998–2013), indicates the occurrence of 3-year W126 exposure index values well above 19 ppm-hrs, a cumulative exposure value for which CASAC termed the associated median RBL estimate ''unacceptably high,'' in multiple Class I areas that meet the current standard (79 FR 75312, December 17, 2014, Table 7; updated in Table 3 above). Additionally, analysis of recent air quality data (2011–2013) for all locations across the U.S. indicates 10 monitor locations distributed across two NOAA climatic regions that meet the current standard and at which 3-year W126 index values are above 19 ppm-hrs, with the highest values extending up to 23 ppm-hrs (Wells, 2015b).

In support of their view that the EPA's modeling supports the conclusion that W126 index values of interest are achieved under the current secondary standard, some commenters additionally state that the W126 values in the WREA are overestimated in unmonitored rural areas due to the much greater prevalence of urban monitors across the U.S. The EPA

[194] Although commenters cite to both analyses as if providing the same information, there are many differences in specific aspects of the RIA approach from that of the WREA, which derive, at least in part, from their very different purposes. The RIA is not developed for consideration in the NAAQS review. Rather, it is intended to provide insights and analysis of an illustrative control strategy that states might adopt to meet the revised standard. The EPA does not consider this analysis informative to consideration of the protection provided by the current standard, and the results of the RIA have not been considered in the EPA's decisions on the O_3 standards.

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disagrees with this conclusion. In order to estimate O_3 concentrations in grid cells across a national-scale spatial surface, the WREA applied the VNA spatial interpolation technique after applying the HDDM technique to adjust O_3 concentrations at monitoring sites based on the emissions reductions necessary to just meet the current standard. In estimating concentrations in unmonitored areas, the VNA method considers only the ''neighboring'' monitors, using an inverse distance squared weighting formula, which assigns the greatest influence to the nearest neighboring monitor (U.S. EPA, 2014b, p. 4A–6). By this approach, monitors in less-densely monitored areas contribute to the concentration estimates over much larger areas than do monitors in more-densely monitored areas. In an urban area, neighboring monitors may be quite close to one another, such that any one monitor may only be influencing concentration estimates for a handful of spatial grid cells in the immediate vicinity. By contrast, monitors in rural areas may influence hundreds of grid cells. A specific example of this is the monitor in Great Basin National Park in eastern Nevada. The VNA algorithm assigns very high weights to this monitor for all of the grid cells covering a 100 km radius around it, simply because there are no other monitors in that area and it is the closest. On the other hand, a monitor near downtown Las Vegas may only get a high weight for, and thus exert influence on the concentration estimate in, the one grid cell containing it. We agree with the commenter that urban monitors may influence the spatial surface for some distance away from the urban areas, although the influence wanes with increasing distance from that area and decreasing distance to the next closest monitor. As we lack data for the intervening locations, however, we have no reason to conclude that the VNA surface is overestimating the W126 index values. Further, as was summarized in section IV.A.2 above, and in the WREA, the PA and the proposal (U.S. EPA, 2014b, Table 6–27, section 8.5; U.S. EPA, 2014c, p. 5–49; 79 FR 75323, December 17, 2014), the VNA approach results in a lowering of the highest W126 index values at monitoring sites, which contributes to underestimates of the *highest* W126 index values in each region.

In support of their view that the current standard is adequate, some industry commenters additionally cite WREA analyses for the current standard scenario, including the W126 index estimates in national parks, as showing that the current standard provides more than adequate protection, with alternative scenarios providing only marginal and increasingly uncertain benefits. As we noted in the proposal and section IV.A.2 above, there are an array of uncertainties associated with the W126 index estimates, in the current standard scenario and in the other scenarios, which, as they are inputs to the vegetation risk analyses, are propagated into those analyses (79 FR 75323; December 17, 2014). As a result, consistent with the approach in the proposal, the Administrator has not based her decision with regard to adequacy of the current standard in this review on these air quality scenario analyses.

In support of their view that the current standard provides adequate protection and should not be revised, some commenters described their concerns with any consideration of visible foliar injury in the decision regarding the secondary standard. These commenters variously stated that visible foliar injury cannot be reliably evaluated for adversity given lack of available information, is not an adverse effect on public welfare that must be addressed through a secondary standard, and is not directly relatable to growth suppression (and the EPA's use of RBL captures that effect anyway). Additionally, some state that any associated ecosystem services effects are not quantifiable. In sum, the view of these commenters is that it is not appropriate for the Administrator to place any weight on this O_3 effect in determining the adequacy of the current standard. As an initial matter, the EPA agrees with the comment that the current evidence does not include an approach for relating visible foliar injury to growth suppression,[195] as recognized in section IV.A.1.b above. Further, we note that, similar to decisions in past O_3 reviews, the Administrator's proposed decision in this review recognized the ''complexities and limitations in the evidence base regarding characterizing air quality conditions with respect to the magnitude and extent of risk for visible foliar injury'' and the ''challenges of associated judgments with regard to adversity of such effects to public welfare'' (79 FR 75336; December 17, 2014). Contrary to the implications of the commenters, although the Administrator took into consideration the potential for adverse effects on public welfare from visible foliar injury, she placed weight primarily on growth-related effects of O_3, both in her proposed decision on adequacy and with regard to proposed judgments on what revisions would be appropriate. Although visible foliar injury may impact the public welfare and accordingly has the potential to be adverse to the public welfare (as noted in section IV.B.2 of the proposal), the Administrator placed less weight on visible foliar injury considerations in identifying what revisions to the standard would be appropriate to propose. In considering these effects for this purpose, she recognized ''significant challenges'' in light of ''the variability and the lack of clear quantitative relationship with other effects on vegetation, as well as the lack of established criteria or objectives that might inform consideration of potential public welfare impacts related to this vegetation effect'' (79 FR 75349; December 17, 2014). As summarized in section IV.A.1.a above, the evidence demonstrates a causal relationship of O_3 with visible foliar injury. Accordingly, we note that the uncertainty associated with visible foliar injury is not with regard to whether O_3 causes visible foliar injury. Rather, the uncertainty is, as discussed in sections IV.A.1.b and IV.A.3 above, with the lack of established, quantitative exposure-response functions that document visible foliar injury severity and incidence under varying air quality and environmental conditions and information to support associated judgments on the significance of such responses with regard to associated public welfare impacts. As with the Administrator's proposed decisions on the standard, such considerations also informed her final decisions, described in sections IV.B.3 and IV.C.3 below.

In support of their view that the current standard should be retained, some commenters note the WREA finding for the current standard scenario of no U.S. counties with RYL estimates at or above 5%, the RYL value emphasized by CASAC and state that policy reasons provide support for not focusing on crops in the decision; other commenters state that additional studies on crops and air quality are needed. As

[195] The current evidence indicates that ''[t]he significance of O_3 injury at the leaf and whole plant levels depends on how much of the total leaf area of the plant has been affected, as well as the plant's age, size, developmental stage, and degree of functional redundancy among the existing leaf area'' and ''in some cases, visible foliar symptoms have been correlated with decreased vegetative growth . . . and with impaired reproductive function'' (U.S. EPA, 2013, p. 9–39). The ISA concludes, however, ''it is not presently possible to determine, with consistency across species and environments, what degree of injury at the leaf level has significance to the vigor of the whole plant'' (U.S. EPA, 2013, p. 9–39).

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described previously in this section, and in section IV.A.2 above, an aspect of uncertainties associated with the WREA air quality scenarios, including the current standard scenario, is underestimation of the highest W126 index values, contributing to underestimates in the effects associated with the current standard scenario. The EPA agrees with commenters that additional studies on crops and air quality will be useful to future reviews. Additionally, however, as noted above, the Administrator's proposed conclusion on adequacy of the current standard, as well as her final decision described in section IV.B.3 below, gives less weight to consideration of effects on agricultural crops in recognition of the complicating role of heavy management in that area.

Lastly, we note that many commenters cited the costs of compliance as supporting their view that the standard should not be revised, although as we have described in section I.B above, the EPA may not consider the costs of compliance in determining what standard is requisite to protect public welfare from known or anticipated adverse effects.

3. Administrator's Conclusions on the Need for Revision

Having carefully considered the advice from CASAC and public comments, as discussed above, the Administrator believes that the fundamental scientific conclusions on the welfare effects of O_3 in ambient air reached in the ISA and summarized in the PA and in section IV.B of the proposal remain valid. Additionally, the Administrator believes the judgments she reached in the proposal (section IV.D.3) with regard to consideration of the evidence and quantitative assessments and advice from CASAC remain appropriate. Thus, as described below, the Administrator concludes that the current secondary standard is not requisite to protect public welfare from known and anticipated adverse effects associated with the presence of O_3 in the ambient air and that revision is needed to provide additional protection.

In considering the adequacy of the current secondary O_3 standard, the Administrator has carefully considered the available evidence, analyses and conclusions contained in the ISA, including information newly available in this review; the information, quantitative assessments, considerations and conclusions presented in the PA; the advice and recommendations from CASAC; and public comments. The Administrator gives primary consideration to the evidence of growth effects in well-studied tree species and information, presented in the PA and represented with a narrower focus in section IV.B.2 above, on cumulative exposures occurring in Class I areas when the current standard is met. This information indicates the occurrence of exposures associated with Class I areas during periods when the current standard is met for which associated estimates of growth effects, in terms of the tree seedling RBL in the median species for which E–R functions have been established, extend above a magnitude considered to be ''unacceptably high'' by CASAC. This analysis estimated such cumulative exposures occurring under the current standard for nearly a dozen areas, distributed across two NOAA climatic regions of the U.S. The Administrator gives particular weight to this analysis, given its focus in Class I areas. Such an emphasis on lands afforded special government protections, such as national parks and forests, wildlife refuges, and wilderness areas, some of which are designated Class I areas under the CAA, is consistent with such emphasis in the 2008 revision of the secondary standard (73 FR 16485, March 27, 2008). As noted in section IV.A above, Congress has set such lands aside for specific uses that are intended to provide benefits to the public welfare, including lands that are to be protected so as to conserve the scenic value and the natural vegetation and wildlife within such areas, and to leave them unimpaired for the enjoyment of future generations. The Administrator additionally recognizes that states, tribes and public interest groups also set aside areas that are intended to provide similar benefits to the public welfare for residents on those lands, as well as for visitors to those areas.

As noted in prior reviews, judgments regarding effects that are adverse to public welfare consider the intended use of the ecological receptors, resources and ecosystems affected. Thus, the Administrator recognizes that the median RBL estimate for the studied species is a quantitative tool within a larger framework of considerations pertaining to the public welfare significance of O_3 effects on the public welfare. Such considerations include effects that are associated with effects on growth and that the ISA has determined to be causally or likely causally related to O_3 in ambient air, yet for which there are greater uncertainties affecting our estimates of impacts on public welfare. These other effects include reduced productivity in terrestrial ecosystems, reduced carbon sequestration in terrestrial ecosystems, alteration of terrestrial community composition, alteration of below-grown biogeochemical cycles, and alteration of terrestrial ecosystem water cycles, as summarized in section IV.A.1. Thus, in her attention to CASAC's characterization of a 6% estimate for tree seedling RBL in the median studied species as ''unacceptably high'', the Administrator, while mindful of uncertainties with regard to the magnitude of growth impact that might be expected in mature trees, is also mindful of related, broader, ecosystem-level effects for which our tools for quantitative estimates are more uncertain and those for which the policy foundation for consideration of public welfare impacts is less well established. She finds her consideration of tree growth effects consistent with CASAC advice regarding consideration of O_3-related biomass loss as a surrogate for the broader array of O_3 effects at the plant and ecosystem levels.

The Administrator also recognizes that O_3-related effects on sensitive vegetation can occur in other areas that have not been afforded special federal protections, including effects on vegetation growing in managed city parks and residential or commercial settings, such as ornamentals used in urban/suburban landscaping or vegetation grown in land use categories that are heavily managed for commercial production of commodities such as timber. In her consideration of the evidence and quantitative information of O_3 effects on crops, the Administrator recognizes the complexity of considering adverse O_3 impacts to public welfare due to the heavy management common for achieving optimum yields and market factors that influence associated services. In so doing, she notes that her judgments that place emphasis on the protection of forested ecosystems inherently also recognize a level of protection for crops. Additionally, for vegetation used for residential or commercial ornamental purposes, the Administrator believes that there is not adequate information specific to vegetation used for those purposes, but notes that a secondary standard revised to provide protection for sensitive natural vegetation and ecosystems would likely also provide some degree of protection for such vegetation.

The Administrator also takes note of the long-established evidence of consistent association of the presence of visible foliar injury with O_3 exposure and the currently available information that indicates the occurrence of visible foliar injury in sensitive species of

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vegetation during recent air quality in public forests across the U.S. She additionally notes the PA conclusions regarding difficulties in quantitatively relating visible foliar injury symptoms to vegetation effects such as growth or related ecosystem effects. As at the time of the last review, the Administrator believes that the degree to which such effects should be considered to be adverse depends on the intended use of the vegetation and its significance. The Administrator also believes that the significance of O_3-induced visible foliar injury depends on the extent and severity of the injury and takes note of studies in the evidence base documenting increased severity and/or prevalence with higher O_3 exposures. However, the Administrator takes note of limitations in the available information with regard to judging the extent to which the extent and severity of visible foliar injury occurrence associated with conditions allowed by the current standard may be considered adverse to public welfare.

Based on these considerations, and taking into consideration the advice and recommendations of CASAC, the Administrator concludes that the protection afforded by the current secondary O_3 standard is not sufficient and that the standard needs to be revised to provide additional protection from known and anticipated adverse effects to public welfare, related to effects on sensitive vegetation and ecosystems, most particularly those occurring in Class I areas. The Administrator additionally recognizes that states, tribes and public interest groups also set aside areas that are intended to provide similar benefits to the public welfare for residents on those lands, as well as for visitors to those areas. Given the clear public interest in and value of maintaining these areas in a condition that does not impair their intended use, and the fact that many of these areas contain O_3-sensitive vegetation, the Administrator further concludes that it is appropriate to revise the secondary standard in part to provide increased protection against O_3-caused impairment to vegetation and ecosystems in such areas, which have been specially protected to provide public welfare benefits. She further notes that a revised standard would provide increased protection for other growth-related effects, including for crop yield loss, reduced carbon storage and for areas for which it is more difficult to determine public welfare significance, as recognized in section IV.A.3 above, as well other welfare effects of O_3, such as visible foliar injury.

C. Conclusions on Revision of the Secondary Standard

The elements of the standard—indicator, averaging time, form, and level—serve to define the standard and are considered collectively in evaluating the welfare protection afforded by the secondary standard. Section IV.C.1 below summarizes the basis for the proposed revision. Significant comments received from the public on the proposal are discussed in section IV.C.2 and the Administrator's final decision on revisions to the secondary standard is described in section IV.C.3.

1. Basis for Proposed Revision

At the time of proposal, in considering what revisions to the secondary standard would be appropriate, the Administrator considered the ISA conclusions regarding the weight of the evidence for a range of welfare effects associated with O_3 in ambient air and associated areas of uncertainty; quantitative risk and exposure analyses in the WREA for different adjusted air quality scenarios and associated limitations and uncertainties; staff evaluations of the evidence, exposure/risk information and air quality information in the PA; additional air quality analyses of relationships between air quality metrics based on form and averaging time of the current standards and a cumulative seasonal exposure index; CASAC advice; and public comments received as of that date in the review. In the paragraphs below, we summarize the proposal presentation with regard to key aspects of the PA considerations, advice from the CASAC, air quality analyses of different air quality metrics and the Administrator's proposed conclusions, drawing from section IV.E of the proposal.

a. Considerations and Conclusions in the PA

As summarized in the proposal, in identifying alternative secondary standards appropriate to consider in this review, the PA focused on standards based on a cumulative, seasonal, concentration-weighted form consistent with the CASAC advice in the current and last review. Based on conclusions of the ISA, as also summarized in section IV.A above, the PA considered a cumulative, seasonal, concentration-weighted exposure index to provide the most scientifically defensible approach for characterizing vegetation response to ambient O_3 and comparing study findings, as well as for defining indices for vegetation protection, as summarized in the proposal section IV.E.2.a. With regard to the appropriate index, the PA considered the evidence for a number of different such indices, as described in the proposal, and noted the ISA conclusion that the W126 index has some important advantages over other similarly weighted indices. The PA additionally considered the appropriate diurnal and seasonal exposure periods in a given year by which to define the seasonal W126 index and based on the evidence in the ISA and CASAC advice, as summarized in the proposal, decided on the 12-hour daylight window (8:00 a.m. to 8:00 p.m.) and the 3-consecutive-month period providing the maximum W126 index value.

Based on these considerations, the PA concluded it to be appropriate to retain the current indicator of O_3 and to consider a secondary standard form that is an average of the seasonal W126 index values (derived as described in section IV.A.1.c above) across three consecutive years (U.S. EPA, 2014c, section 6.6). In so doing, the PA recognized that there is limited information to discern differences in the level of protection afforded for cumulative growth-related effects by potential alternative W126-based standards of a single-year form as compared to a 3-year form (U.S. EPA, 2014c, pp. 6–30). The PA concluded a 3-year form to be appropriate for a standard intended to provide the desired level of protection from longer-term effects, including those associated with potential compounding, and that such a form might be concluded to contribute to greater stability in air quality management programs, and thus, greater effectiveness in achieving the desired level of public welfare protection than might result from a single-year form. (U.S. EPA, 2014c, section 6.6).

As summarized in the proposal, the PA noted that, due to the variability in the importance of the associated ecosystem services provided by different species at different exposures and in different locations, as well as differences in associated uncertainties and limitations, it is essential to consider the species present and their public welfare significance, together with the magnitude of the ambient concentrations in drawing conclusions regarding the significance or magnitude of public welfare impacts. Therefore, in development of the PA conclusions, staff took note of the complexity of judgments to be made by the Administrator regarding the adversity of known and anticipated effects to the

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public welfare and recognized that the Administrator's ultimate judgments on the secondary standard will most appropriately reflect an interpretation of the available scientific evidence and exposure/risk information that neither overstates nor understates the strengths and limitations of that evidence and information. In considering an appropriate range of levels to consider for an alternative standard, the PA primarily considered tree growth, crop yield loss, and visible foliar injury, as well as impacts on the associated ecosystem services, while noting key uncertainties and limitations.

In specifically evaluating exposure levels, in terms of the W126 index, as to their appropriateness for consideration in this review with regard to providing the desired level of vegetation protection for a revised secondary standard, the PA focused particularly on RBL estimates for the median across the 11 tree species for which robust E–R functions are available. Table 4 below presents these estimates (U.S. EPA, 2014c, Appendix 5C, Table 5C–3; also summarized in Table 8 of the proposal). In so doing and recognizing the longstanding, strong evidence base supporting these relationships, the PA also noted uncertainties regarding inter-study variability for some species, as well as with regard to the extent to which tree seedling E–R functions can be used to represent mature trees. As summarized in the proposal, the PA conclusions on a range of W126 levels appropriate to consider are based on specific advice from CASAC with regard to median tree seedling RBL estimates that might be considered unacceptably high (6%), as well as its judgment on a RBL benchmark (2%) for identification of the lower end of a W126 index value range for consideration that might give more emphasis to the more sensitive tree seedlings (Frey, 2014c, p. 14).[196]

TABLE 4—TREE SEEDLING BIOMASS LOSS AND CROP YIELD LOSS ESTIMATED FOR O_3 EXPOSURE OVER A SEASON

W126 index value for exposure period	Tree seedling biomass loss [A]		Crop yield loss [B]	
	Median value	Individual species	Median value	Individual species
23 ppm-hrs	Median species w. 7.6% loss	≤ 2% loss: 3/11 species ≤ 5% loss: 4/11 species ≤10% loss: 8/11 species ≤15% loss: 10/11 species >40% loss: 1/11 species	Median species w. 8.8% loss	≤ 5% loss: 4/10 species >5,<10% loss: 1/10 species >10,<20% loss: 4/10 species >20: 1/10 species
22 ppm-hrs	Median species w. 7.2% loss	≤ 2% loss: 3/11 species ≤ 5% loss: 4/11 species ≤10% loss: 7/11 species ≤15% loss: 10/11 species >40% loss: 1/11 species	Median species w. 8.2% loss	≤ 5% loss: 4/10 species >5,<10% loss: 1/10 species >10,<20% loss: 4/10 species >20: 1/10 species
21 ppm-hrs	Median species w. 6.8% loss	≤ 2% loss: 3/11 species ≤ 5% loss: 4/11 species ≤10% loss: 7/11 species ≤15% loss: 10/11 species >40% loss: 1/11 species	Median species w. 7.7% loss	≤ 5% loss: 4/10 species >5,<10% loss: 3/10 species >10,<20% loss: 3/10 species
20 ppm-hrs	Median species w. 6.4% loss	≤ 2% loss: 3/11 species ≤ 5% loss: 5/11 species ≤10% loss: 7/11 species ≤15% loss: 10/11 species >40% loss: 1/11 species	Median species w. 7.1% loss	≤ 5% loss: 5/10 species >5,<10% loss: 3/10 species >10,<20% loss: 2/10 species
19 ppm-hrs	Median species w. 6.0% loss	≤ 2% loss: 3/11 species ≤5% loss: 5/11 species ≤10% loss: 7/11 species ≤15% loss: 10/11 species >30% loss: 1/11 species	Median species w. 6.4% loss	≤ 5% loss: 5/10 species >5, <10% loss: 3/10 species >10,<20% loss: 2/10 species
18 ppm-hrs	Median species w. 5.7% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 5/11 species ≤10% loss: 7/11 species ≤15% loss: 10/11 species >30% loss: 1/11 species	Median species w. 5.7% loss	≤ 5% loss: 5/10 species >5,<10% loss: 3/10 species >10,<20% loss: 2/10 species
17 ppm-hrs	Median species w. 5.3% loss	≤ 2% loss: 5/11 species ≤5% loss: 5/11 species ≤10% loss: 9/11 species ≤15% loss: 10/11 species >30% loss: 1/11 species	Median species w. 5.1% loss	≤ 5% loss: 5/10 species >5, <10% loss: 3/10 species >10,<20% loss: 2/10 species
16 ppm-hrs	Median species w. 4.9% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 6/11 species ≤10% loss: 10/11 species >30% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 5/10 species >5,<10% loss: 4/10 species >10,<20% loss: 1/10 species
15 ppm-hrs	Median species w. 4.5% loss	≤ 2% loss: 5/11 species ≤5% loss: 6/11 species ≤10% loss: 10/11 species >30% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 6/10 species >5, <10% loss: 4/10 species
14 ppm-hrs	Median species w. 4.2% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 6/11 species ≤10% loss: 10/11 species >30% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 6/10 species >5,<10% loss: 4/10 species
13 ppm-hrs	Median species w. 3.8% loss	≤ 2% loss: 5/11 species <5% loss: 7/11 species <10% loss: 10/11 species >20% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 6/10 species >5, <10% loss: 4/10 species

[196] The CASAC provided several comments related to 2% RBL for tree seedlings both with regard to its use in summarizing WREA results and with regard to consideration of the potential significance of vegetation effects, as summarized in sections IV.D.2 and IV.E.3 of the proposal.

TABLE 4—TREE SEEDLING BIOMASS LOSS AND CROP YIELD LOSS ESTIMATED FOR O_3 EXPOSURE OVER A SEASON—Continued

W126 index value for exposure period	Tree seedling biomass loss [A]		Crop yield loss [B]	
	Median value	Individual species	Median value	Individual species
12 ppm-hrs	Median species w. 3.5% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 8/11 species ≤10% loss: 10/11 species >20% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 8/10 species >5,<10% loss: 2/10 species
11 ppm-hrs	Median species w. 3.1% loss	≤ 2% loss: 5/11 species ≤5% loss: 8/11 species ≤10% loss: 10/11 species >20% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 9/10 species >5, <10% loss: 1/10 species
10 ppm-hrs	Median species w. 2.8% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 9/11 species <10% loss: 10/11 species >20% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: 9/10 species >5,<10% loss: 1/10 species
9 ppm-hrs	Median species w. 2.4% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 10/11 species >20% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: all species
8 ppm-hrs	Median species w. 2.0% loss	≤ 2% loss: 5/11 species ≤ 5% loss: 10/11 species >15% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: all species
7 ppm-hrs	Median species w. <2.0% loss	≤ 2% loss: 7/11 species ≤5% loss: 10/11 species >15% loss: 1/11 species	Median species w. ≤5.0% loss	≤ 5% loss: all species

[A] Estimates here are based on the E–R functions for 11 species described in the WREA, section 6.2 and discussed in the PA, section 5.2.1. The cottonwood was excluded to address CASAC comments (Frey, 2014c; U.S. EPA, 2014b, U.S. EPA, 2014c, Appendix 6F). The median is the median of the 11 composite E–R functions (U.S. EPA, 2014c, Appendix 5C).

[B] Estimates here are based on the 10 E–R functions for crops described in the WREA, section 6.2 and discussed in the PA, section 5.3.1. The median is the median of the 10 composite E–R functions (U.S. EPA, 2014b; U.S. EPA, 2014c, Appendix 5C).

With regard to secondary standard revisions appropriate to consider in this review, as summarized in the proposal, the PA concluded it to be appropriate to consider a W126-based secondary standard with index values within the range of 7 to 17 ppm-hrs and a form averaged over 3 years (U.S. EPA, 2014c, section 6.7). The PA additionally recognized the role of policy judgments required of the Administrator with regard to the public welfare significance of identified effects, the appropriate weight to assign the range of uncertainties inherent in the evidence and analyses, and ultimately, in identifying the requisite protection for the secondary O_3 standard.

The PA additionally recognized that to the extent the Administrator finds it useful to consider the public welfare protection that might be afforded by revising the level of the current standard, this is appropriately judged by evaluating the impact of associated O_3 exposures in terms of the cumulative seasonal W126-based index, an exposure metric considered appropriate for evaluating impacts on vegetation (U.S. EPA, 2014c, section 6.7). Accordingly, the PA included several air quality data analyses that might inform such consideration (U.S. EPA, 2014c, section 6.4). Additional air quality analyses were performed subsequent to the PA, described in the proposal and are summarized below.

b. CASAC Advice

Advice received from the CASAC during the current review, similar to that in the last review, recommended retaining O_3 as the indicator, while also recommending consideration of a secondary standard with a revised form and averaging time based on the W126 index (Frey, 2014c, p. iii). The CASAC concurred with the 12-hour period (8 a.m. to 8 p.m.) and 3-month summation period resulting in the maximum W126 index value, as described in the PA, while recommending a somewhat narrower range of levels from 7 ppm-hrs to 15 ppm-hrs. While the CASAC recommended a W126 index limited to a single year, in contrast with the PA's conclusion that it was appropriate to consider the W126 index averaged across three years, it also noted that the Administrator may prefer, as a policy matter, to base the secondary standard on a 3-year averaging period. In such a case, the CASAC recommended revising downward the level for such a metric to avoid a seasonal W126 index value above a level in their recommended range in any given year of the 3-year period, indicating an upper end of 13 ppm-hrs as an example for such a 3-year average W126 index range (Frey, 2014c, p. iii and iv).

c. Air Quality Analyses

The proposal additionally summarized several analyses of air quality that considered relationships between metrics based on a 3-year W126 index and based on the form and averaging time of the current standard, the "fourth-high" metric (U.S. EPA, 2014c, Chapter 2, Appendix 2B and section 6.4; Wells, 2014a), as well as describing the uncertainties and limitations associated with these analyses. The proposal concluded that these analyses suggest that, depending on the level, a standard of the current averaging time and form can be expected to control cumulative seasonal O_3 exposures to such that they may meet specific 3-year average W126 index values. The fourth-high and W126 metrics, and changes in the two metrics over the past decade, were found to be highly correlated (U.S. EPA, 2014c, section 6.4 and Appendix 2B; Wells, 2014a). From these analyses, it was concluded that future control programs designed to help meet a standard based on the fourth-high metric are also expected to result in reductions in values of the W126 metric (Wells, 2014a). Further, the second analysis also found that the Southwest and West NOAA climatic regions, which showed the greatest potential for sites to measure elevated cumulative, seasonal O_3 exposures without the occurrence of elevated daily maximum 8-hour average O_3 concentrations, exhibited the greatest reduction in W126 metric value per unit reduction in fourth-high metric (Wells, 2014a, Figures 5b and 12 and Table 6).

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Analyses of the most recent periods studied in the two analyses (2009–2011 and 2011–2013) had similar findings regarding the highest W126 metric values occurring at monitoring sites that meet alternative levels of the fourth-high metric (U.S. EPA, 2014c, section 6.4; Wells, 2014a). In both analyses, the highest W126 metric values were in the Southwest and West NOAA climatic regions. In both analyses, no monitoring sites for which the fourth-high metric was at or below 70 ppb had a W126 metric value above 17 ppm-hrs (U.S. EPA, 2014c, Figure 2B–3b; Wells, 2014a, Table 4). All U.S. regions were represented in these subsets. In the 2011–2013 subset of sites for which the fourth-high metric was at or below a potential alternative primary standard level of 65 ppb, no monitoring sites had W126 metric values above 11 ppm-hrs (Wells, 2014a, Table 4).

d. Administrator's Proposed Conclusions

At the time of proposal, the Administrator concluded it to be appropriate to continue to use O_3 as the indicator for a secondary standard that is intended to address effects associated with exposure to O_3 alone and in combination with related photochemical oxidants. While the complex atmospheric chemistry in which O_3 plays a key role has been highlighted in this review, no alternatives to O_3 have been advanced as being a more appropriate surrogate for ambient photochemical oxidants and their effects on vegetation. The CASAC agreed that O_3 should be retained as the indicator for the standard (Frey, 2014c, p. iii). In proposing to retain O_3 as the indicator, the Administrator recognized that measures leading to reductions in ecosystem exposures to O_3 would also be expected to reduce exposures to other photochemical oxidants.

The Administrator proposed to retain the current averaging time and form and to revise the level of the current secondary standard to a level within the range of 0.065 to 0.070 ppm. She based this proposal on her provisional conclusions regarding the level of cumulative seasonal O_3 exposures that would provide the requisite protection against known or anticipated adverse effects to the public welfare and on a policy option that would provide this level of protection. With regard to the former, the Administrator concluded that in judging the extent of public welfare protection that might be afforded by a revised standard and whether it meets the appropriate level of protection, it is appropriate to use a cumulative, seasonal concentration-weighted exposure metric. For this purpose, the Administrator concluded it to be appropriate to use the W126 index value, averaged across three years, with each year's value identified as that for the 3-month period yielding the highest seasonal value and with daily O_3 exposures within a 3-month period cumulated for the 12-hour period from 8:00 a.m. to 8:00 p.m.

To identify the range of cumulative seasonal exposures, in terms of the W126 index, expected to be associated with the appropriate degree of public welfare protection, the Administrator gave primary consideration to growth-related impacts, using tree seedling RBL estimates for a range of W126 exposure index values and CASAC advice regarding such estimates. Additionally taking into account judgments on important uncertainties and limitations inherent in the current available scientific evidence and quantitative assessments, and judgments regarding the extent to which different RBL estimates might be considered indicative of effects adverse to public welfare, the Administrator proposed that ambient O_3 concentrations resulting in cumulative seasonal O_3 exposures of a level within the range from 13 ppm-hrs to 17 ppm-hrs, in terms of a W126 index averaged across three consecutive years, would provide the requisite protection against known or anticipated adverse effects to the public welfare. In identifying policy options for a revised secondary standard that would control exposures to such an extent, the Administrator considered the results of air quality analyses that examined the responsiveness of cumulative exposures (in terms of the W126 index) to O_3 reductions in response to the current and prior standard for which the form and averaging time are summarized as a fourth-high metric, and also examined the extent to which cumulative exposures (in terms of the W126 index) may be limited by alternative levels of a metric based on the current standard averaging time and form. Based on the results of these analyses, she proposed that revision of the level of the current secondary standard to within the range of 0.065 to 0.070 ppm would be expected to provide the requisite public welfare protection, depending on final judgments concerning such requisite protection.

2. Comments on Proposed Revision

Significant comments from the public regarding revisions to the secondary standard are addressed in the subsections below. We first discuss comments related to our consideration of growth-related effects and visible foliar injury in identifying appropriate revisions to the standard (sections IV.C.2.a and IV.C.2.b). Next, we address comments related to the use of the W126 metric in evaluating vegetation effects and public welfare protection and comments related to the form and averaging time for the revised standard (sections IV.C.2.c and IV.C.2.d). Comments on revisions to the level of the standard are described in section IV.C.2.e, and those related to the way in which today's rulemaking addresses the 2013 court remand are addressed in section IV.C.2.f. Other significant comments related to consideration of a revised secondary standard, and that are based on relevant factors, are addressed in the Response to Comments document.

a. Consideration of Growth-Related Effects

In considering public comments received on the consideration of growth-related effects of O_3 in the context of the proposed decision on a revised secondary standard, we first note related advice and comments from the CASAC provided during development of the PA, stating, as summarized in section IV.B.1.b above, that ''relative biomass loss for tree species, crop yield loss, and visible foliar injury are appropriate surrogates for a wide range of damage that is adverse to public welfare'' (Frey, 2014c, p. 10). Additionally, in the context of different standard levels they considered appropriate for the EPA to consider, CASAC stated that it is appropriate to ''include[] levels that aim for not greater than 2% RBL for the median tree species'' and that a median tree species RBL of 6% is ''unacceptably high'' (Frey, 2014c, p. 14).[197] With respect to crop yield loss, CASAC points to a benchmark of 5%, stating that a crop RYL for median species over 5% is ''unacceptably high'' (Frey, 2014c, p. 13).

In addition, regarding consideration of RBL benchmarks for tree seedlings, the CASAC stated that ''[a] 2% biomass loss is an appropriate scientifically based value to consider as a benchmark of adverse impact for long-lived perennial species such as trees, because effects are cumulative over multiple

[197] The CASAC made this comment while focusing on Table 6–1 in the second draft PA and the entry for 17 ppm-hrs (Frey, 2014c, p. 14). That table was revised for inclusion in the final PA in consideration of CASAC comments on the E–R function for eastern cottonwood, and after that revision, the median RBL estimate for 17 ppm-hrs in the final table (see Table 4 above) is below the value of 6% that CASAC described in this way.

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years'' (Frey, 2014c, p. 14).[198] With regard to this benchmark, the CASAC also commented that ''it is appropriate to identify a range of levels of alternative W126-based standards that includes levels that aim for not greater than 2% RBL for the median tree species'' in the PA (Frey, 2014c, p. 14). The CASAC noted that the ''level of 7 ppm-hrs is the only level analyzed for which the relative biomass loss for the median tree species is less than or equal to 2 percent,'' indicating that 7 ppm was appropriate as a lower bound for the recommended range (Frey, 2014c, p. 14).[199]

With regard to consideration of effects on crops, in addition to their comments regarding a median species RYL over 5% yield loss, noted above (Frey, 2014c, p. 13), the CASAC further noted that ''[c]rop loss appears to be less sensitive than these other indicators, largely because of the CASAC judgment that a 5% yield loss represents an adverse impact, and in part due to more opportunities to alter management of annual crops'' (Frey, 2014c, p. 14).

Comments from the public with regard to how the EPA considered growth-related effects in the proposed decision on a revised secondary standard varied. Generally, those commenters who recommended against revision of the standard expressed the view that RBL estimates based on the established E–R functions for the 11 studied species, and their pertinence to mature trees, were too uncertain to serve as a basis for judgments regarding public welfare protection afforded by the secondary standard. The EPA generally disagrees with this view, as discussed in section IV.B.2 above, and addressed in more detail in the Response to Comments document.

Some commenters also took note of the unclear basis for CASAC's 2% benchmark, stating that the CASAC advice on this point is ''not wholly scientific,'' given that it referenced the 1996 workshop, which provided little specificity as to scientific basis for such a benchmark; based on this, the commenters described this CASAC advice as a policy judgment and described the important role of the EPA's judgment in such instances. As noted in section IV.E.3 of the proposal, we generally agree with these commenters regarding the unclear scientific basis for the 2% value. Consistent with this advice from CASAC, however, the range of levels for a revised secondary standard that the PA concluded was appropriate for the Administrator to consider did include a level for which the estimated median RBL across the 11 studied tree species would be 2%, as well as a level for which the median RBL would be below 2% (U.S. EPA, 2014c, section 6.7 and Tables 6–1 and 5C–3), and, as described in the proposal, the Administrator considered the conclusions of the PA in reaching her proposed decision that it was appropriate to consider a range for the revised secondary standard that did not focus on this benchmark. The Administrator has further considered and explained any differences from CASAC's recommendations on this point in her final decision, as described in section IV.C.3 below.

Some of the state and local environmental agencies and organizations and environmental groups that supported the EPA's proposed decision to revise the secondary standard additionally indicated their view that the EPA should give more weight to growth-related effects by setting the standard at a level for which the estimated RBL would be at or below 2% in the median studied species. In support of this recommendation, the commenters cited the CASAC advice and stated that the EPA's rationale deviates from that advice with regard to consideration of RBL. In so doing, the commenters implied incorrectly that the EPA's proposal did not put the most weight on the median RBL. In fact, in considering RBL as a metric for growth effects, the Administrator's proposed conclusions focused solely on the median RBL estimates, indicating that appreciable weight was given to growth-related effects and on the median RBL. Additionally, the commenters implied that the EPA misconstrued the CASAC comment on 6% RBL to indicate that it was acceptable. Yet, the proposal notes CASAC's view that a 6% RBL is ''unacceptably high'' nine times, and, in section IV.B.3 above, the Administrator takes note of this view in reaching the decision that the current standard should be revised. The EPA considers this statement from CASAC, provided in the context of considering effects related to different W126 index values, to be of a different nature than CASAC advice discussed above that options for the EPA consideration ''include'' a level that aims for median RBL at or below 2%.

The comments that state that the standard should control cumulative exposures to levels for which the estimated median species RBL is at or below 2% provided little rationale beyond citing to CASAC advice. We note, however, that the CASAC did not specify that the revised secondary standard be set to limit cumulative exposures to that extent. Nor, in identifying a range of alternatives for the EPA to consider, did CASAC recommend that the EPA consider *only* W126 index levels associated with median RBL estimates at or below 2%. Rather, the CASAC stated that ''it is appropriate to identify a range of levels of alternative W126-based standards that *includes* {emphasis added} levels that aim for not greater than 2% RBL for the median tree species'' (Frey, 2014c, p. 14) and seven of the nine levels in the CASAC-recommended range of W126 index levels were associated with higher RBL estimates (as shown in Table 4 above).

In citing to CASAC advice, commenters quoted the CASAC characterization of a 2% RBL as ''an appropriate scientifically based value to consider as a benchmark of adverse impact for long-lived perennial species such as trees, because effects are cumulative over multiple years'' (Frey, 2014, p. 14). Presumably to indicate reasoning for this statement, the subsequent sentence in the same CASAC letter referenced findings for biomass loss in aspen exposed to elevated O_3 over seven years, citing Wittig et al., 2009. As noted in the proposal, however, the way in which these findings would provide a basis for CASAC's view with regard to 2% is unclear, as the original publication that is the source for the 7-year biomass loss value (King, et al., 2005) and which is cited in Wittig et al. (2009) indicates yearly RBL values during this 7-year exposure that are each well above 2%, and, in fact, are all above 20% (King, et al., 2005). In the same paragraph, the CASAC letter additionally referenced the report of the 1996 workshop sponsored by the Southern Oxidants Study group (Heck and Cowling, 1997, noted in section IV.A.3 above). The workshop report identified 1–2% per year growth reduction (based on a stated interest in avoiding 2% cumulative effects) as an appropriate endpoint for consideration of growth effects in trees, although an explicit rationale for the identified percentages is not provided

[198] The CASAC provided several comments related to 2% RBL for tree seedlings both with regard to its use in summarizing WREA results and with regard to consideration of the potential significance of vegetation effects, as summarized in sections IV.D.2 and IV.E.3 of the proposal.

[199] The CASAC made this comment while focusing on Table 6–1 in the second draft PA, which included odd-numbered W126 index values and in which the median RBL values were based on 12 species. That table was revised for inclusion in the final PA in consideration of CASAC comments on the E-R function for eastern cottonwood, such that the median RBL species estimate for both 7 ppm-hrs and 8 ppm-hrs are less than or equal to 2.0% in the final table (see Table 4 above and Table 5C–3 of the final PA).

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(Frey, 2014c, p. 14).[200] Like the 1996 workshop, the CASAC describes 2% RBL as providing the basis for consideration of 7 ppm-hrs, the lower end of their recommended W126 range (Frey, 2014c, p. 14). As a result, the specific scientific basis for judging a value of 2% RBL in the median studied species as an appropriate benchmark of adverse impact for trees and other long-lived perennials is not clear, which, as described in the proposal, contributed to the Administrator noting the greater uncertainty regarding the extent to which estimates of benefits in terms of ecosystem services and reduced effects on vegetation at O_3 exposures below her identified range of 13 to 17 ppm-hrs might be judged significant to the public welfare.

Some commenters recommended revision of the standard to 7 ppm-hrs as a W126 form stating that such a change is needed to protect against climate change. In so doing, one commenter expressed the view that the relatively lesser weight the EPA placed on the WREA estimates of carbon storage (in terms of CO_2) in consideration of a proposed revision to the secondary standard is inconsistent with the emphasis that the EPA placed on CO_2 emissions reductions estimated for the proposed Clean Power Plan (79 FR 34830, 34931–33). As support for this view of inconsistency, the commenter compared the WREA 30-year estimate of the amount of CO_2 removed from the air and stored in vegetation with estimated reductions in CO_2 emissions from power plants over a 4-year period. We note, however, some key distinctions between the two types of estimates which appropriately lead to different levels of emphasis by the EPA in the two actions. First, we note that the lengths of time pertaining to the two estimates that the commenter states to be ''roughly equal'' (*e.g.,* ALA et al., p. 211) differ by more than a factor of seven (4 years compared to 30). Second, the CPP estimates are for reductions in CO_2 produced and emitted from power plants, while the WREA estimates are for amounts of CO_2 removed from the air and stored in vegetation as a result of plant photosynthesis occurring across the U.S. This leads to two important differences. The first is whether a ton of additional carbon uptake by plants is equal to a ton of reduced emissions from fossil fuels. This is still an active area of discussion due in part to the potentially transient nature of the carbon storage in vegetation. The second is that there are much larger uncertainties involved in attempting to quantify the additional carbon uptake by plants which requires complex modeling of biological and ecological processes and their associated sources of uncertainty. Therefore, as summarized in section IV.C.3 below, the Administrator is judging, as at the time of proposal, that the quantitative uncertainties are too great to support identification of a revised standard based specifically on the WREA quantitative estimates of carbon storage benefits to climate. In so doing, she notes that a revised standard, established primarily based on other effects for which our quantitative estimates are less uncertain, can be expected to also provide increased protection in terms of carbon storage.

b. Consideration of Visible Foliar Injury

In considering public comments received on the EPA's consideration of visible foliar injury in its decision on a revised secondary standard, the EPA first notes related advice and comments from the CASAC received during development of the PA. The CASAC stated that ''[w]ith respect to the secondary standard, the CASAC concurs with the EPA's identification of adverse welfare effects related to . . . damage to resource use from foliar injury'' (Frey, 2014, p. iii). In its comments on levels of a W126-based standard, the CASAC, seemingly in reference to the WREA visible foliar injury analyses, additionally stated that ''[a] level below 10 ppm-hrs is required to reduce foliar injury'' (Frey, 2014, pp. iii and 15), with ''W126 values below 10 ppm-hr required to reduce the number of sites showing visible foliar injury'' (Frey, 2014, p. 14).

Public comments were generally split between two views, either that visible foliar injury was not appropriate to consider in decisions regarding the standard, based on variously identified reasons, or that it should be considered and it would lead the EPA to focus on a W126 value below approximately 10 ppm-hrs. Comments of the former type are discussed in section IV.B.2 above, with, in some cases, additional detail in the Response to Comments document. Commenters expressing the latter view variously cite CASAC advice and figures from the WREA cumulative analysis of USFS biosite data with WREA W126 index value estimates. The EPA disagrees that only a reduction in cumulative exposures to W126 index values below 10 ppm-hrs will affect the occurrence or extent of visible foliar injury. In so doing, we note that the extensive evidence, which is summarized in the ISA (including studies of the USFS biomonitoring program), analyses in the 2007 Staff Paper and also observations based on the WREA dataset do not support this conclusion.

The evidence regarding visible foliar injury as an indicator of O_3 exposure is well established and generally documents a greater extent and severity of visible foliar injury with higher O_3 exposures and a modifying role of soil moisture conditions (U.S. EPA, 2013, section 9.4.2). As stated in the ISA, ''[v]isible foliar injury resulting from exposure to O_3 has been well characterized and documented over several decades of research on many tree, shrub, herbaceous and crop species'' and ''[o]zone-induced visible foliar injury symptoms on certain bioindicator plant species are considered diagnostic as they have been verified experimentally'' (U.S. EPA, 2013, p. 9–41). Further, a recent study highlighted in the ISA, which analyzed trends in the incidence and severity of foliar injury, reported a declining trend in the incidence of foliar injury as peak O_3 concentrations declined (U.S. EPA, 2013, p. 9–40; Smith, 2012). Another study available in this review that focused on O_3-induced visible foliar injury in forests of west coast states observed that both percentage of biosites with injury and average biosite index were higher for sites with average cumulative O_3 concentrations above 25 ppm-hrs in terms of SUM06 (may correspond to W126 of approximately 21 ppm-hrs [U.S. EPA, 2007, p. 8–26, Appendix 7B]) as compared to groups of sites with lower average cumulative exposure concentrations, with much less clear differences between the two lower exposure groups (Campbell et al., 2007, Figures 27 and 28 and p. 30). A similar finding was reported in the 2007 Staff Paper which reported on an analysis that showed a smaller percentage of injured sites among the group of sites with O_3 exposures below a SUM06 metric of 15 ppm-hrs or a fourth-high metric of 74 ppb as compared to larger groups that also included sites with SUM06 values up to 25 ppm-hrs or fourth-high metric up to 84 ppb, respectively (U.S. EPA 2007, pp. 7–63 to 7–64).

With regard to the comments referencing the WREA cumulative analysis of USFS FHM/FIA biosite data or related CASAC comments, we note some clarification of this analysis. This analysis does not show, as implied by the comments, that at W126 index values above 10 ppm-hrs, there is little change with increasing W126 index in

[200] The report of the 1996 workshop provides no more explicit rationale for the percentages identified or specification with regard to number or proportion of species for which such percentages should be met (Heck and Cowling, 1997).

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the proportion of records with any visible foliar injury (biosite index above 0). As the analysis is a cumulative analysis, each point graphed in the analysis includes the records for the same and lower W126 index values, so the analysis does not compare results for groups of records with differing, non-overlapping W126 index values. Rather, the points represent groups with records (and W126 index values) in common and the number of records in the groups is greater for higher W126 index values (U.S. EPA, 2014b, section 7.2). Additionally, we note that the pattern observed in the cumulative analysis is substantially influenced by the large number of records for which the W126 index estimates are at or below 11 ppm-hrs, more than two thirds of the dataset (Smith and Murphy, 2015, Table 1).

To more fully address the comments related to this WREA analysis, we have drawn several additional observations from the WREA dataset, re-presenting the same data in a different format in a technical memorandum to the docket (Smith and Murphy, 2015). Contrary to the implication of the statements from the commenters and CASAC that no reduction in the occurrence of visible foliar injury can be achieved with exposures above 10 ppm-hrs, both the proportion of records with injury and the average biosite index are lower for groups of records with W126 index estimates at or below 17 ppm-hrs compared to the group for the highest W126 index range. This is true when considered regardless of soil moisture conditions (all records), as well as for dry, normal and wet records, separately (Smith and Murphy, 2015, Table 2). The pattern of the two measures across record groups with lower W126 index values differs with moisture level, with the wetter than normal records generally showing decreasing proportions of injured sites and decreasing average biosite index with lower W126 index values, while little difference in these measures is seen among the middle W126 values although they are lower than the highest W126 index group and higher than the lowest W126 index group (Smith and Murphy, 2015, Table 2). In summary, the EPA disagrees with commenters, noting that the available information, including additional observations from the WREA dataset, indicate declines in the occurrence of visible foliar injury across decreasing W126 index values that are higher than 10 ppm-hrs.

c. Use of W126 Metric in Evaluating Vegetation Effects and Public Welfare Protection

In considering public comments received on the EPA's use of the W126 exposure index in its decision on a revised secondary standard, the EPA first notes related advice and comments from the CASAC received during development of the PA. Although we recognize that CASAC's comments on the W126 index were provided in the context of its recommendation for a secondary standard of that form, we find them to also relate to our use of the W126 metric in evaluating the magnitude and extent of vegetation effects that might be expected and conversely the level of protection that might be provided under different air quality conditions. In comments on the first draft PA, the CASAC stated that ''discussions and conclusions on biologically relevant exposure metrics are clear and compelling and the focus on the W126 form is appropriate'' (Frey and Samet, 2012a). With regard to specific aspects of the W126 index, the CASAC concurred with the second draft PA focus on ''the biologically-relevant W126 index accumulated over a 12-hour period (8 a.m.–8 p.m.) over the 3-month summation period of a single year resulting in the maximum value of W126'' (Frey, 2014c, p. iii).

The CASAC advice on levels of the W126 index on which to focus for public welfare protection recommended a level within the range of 7 ppm-hrs to 15 ppm-hrs (Frey, 2014c, p. iii). We note, however, as summarized in section IV.E.3 of the proposal, that this advice was provided in the context of the CASAC review of the second draft PA, which concluded that a range from 7 to 17 ppm-hrs was appropriate to consider. In considering the upper end of this range, the CASAC consulted Table 6–1 of the second draft PA which indicated for a W126 index value of 17 ppm-hrs an RBL estimate of 6%, a magnitude that CASAC described as ''unacceptably high'' and that contributed to a lack CASAC support for W126 exposures values higher than 15 ppm-hrs (Frey, 2014c, p. 14; U.S. EPA 2014d, Table 6–1). As noted in section IV.E.3 of the proposal, revisions to the RBL estimate table in the final PA, which were made in consideration of other CASAC comments, have resulted in changes to the median species RBL estimate associated with each W126 index value, such that the median species RBL estimate for a W126 index value of 17 ppm-hrs in this table in the final PA was 5.3%, rather than the ''unacceptably high'' value of 6% (U.S. EPA, 2014c, Table 6–1; U.S. EPA, 2014d, Table 6–1; Frey, 2014c, p. 14).[201] Additionally, the CASAC recognized that the Administrator may, as a policy matter, prefer to use a 3-year average, and stated that in that case, the range of levels should be revised downward (Frey, 2014c, p. iii–iv).

The majority of comments on the W126 index concurred with its use for assessing O_3 exposures, while some commenters additionally expressed the view that this index should be used as the form of the secondary standard (as discussed in section IV.C.2.d below). Most submissions from state and local environmental agencies or governments, as well as organizations of state agencies, that provided comments on the magnitude of cumulative exposure, in terms of the W126 index, appropriate to consider for a revised secondary standard, recommended that the EPA focus on an index value within the EPA's proposed range of 13 to 17 ppm-hrs, as did the industry commenters. These commenters variously noted their agreement with the rationale provided by the EPA in the proposal or cited to CASAC comments, including for a downward adjustment of its recommended values if a 3-year average W126 was used rather than a single year index. Some other commenters, including two groups of environmental organizations, submitted comments recommending a focus on a W126 index level as low as 7 ppm-hrs based on reasons generally focused on consideration of visible foliar injury.

Some aspects of these comments have been addressed in sections IV.C.2.a and IV.C.2.b above. In the Response to Comments document, we have additionally addressed other comments that recommend a focus on W126 index values for specific reasons other than generally citing the CASAC recommended range. Further, in her consideration of a target level of protection for the revised secondary standard in section IV.C.3 below, the Administrator has considered comments from the CASAC regarding the basis for their recommended range.

An additional comment from an organization of western state air quality managers indicated a concern with the use of W126 for vegetation in arid and high altitude regions, such as those in the western states, which the

[201] We additionally note that the median species RBL estimate for 17 ppm-hrs in the final PA is nearly identical to the estimate for 15 ppm-hrs (the value corresponding to the upper end of the CASAC-identified range) that was in the second draft PA (5.2%) which was the subject of the CASAC review (U.S. EPA, 2014c, Table 6–1; U.S. EPA, 2014d, Table 6–1).

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commenter hypothesized may have reduced sensitivity. The commenters did not provide evidence of this hypothesis, calling for further research in order to characterize the sensitivity of vegetation in such areas. The EPA agrees that additional research would be useful in more completely characterizing the response of species in such areas, as well as other less well studied areas, but does not find support in the currently available evidence for the commenter's suggestion that species in arid and high altitude regions may be less sensitive than those in other areas.[202]

Among the small number of commenters recommending against using the W126 metric to assess O_3 exposure, a few expressed the view that some other, not-yet-identified cumulative exposure metric should be used. These commenters cited a variety of concerns that they state are not addressed by the W126 index: that plant exposure to and uptake of O_3 are not always equivalent because of variations in stomatal conductance and plant defenses and their respective diel patterns, which will also influence plant response; that the duration between harmful O_3 exposures affects the plant's ability to repair damage; and, that night-time exposures may be important. These commenters do not identify an alternative to the W126 index that they conclude to better represent exposures relevant to considering O_3 effects on vegetation and particularly for growth effects. The EPA has considered the items raised by these commenters, recognizing some as areas of uncertainty (U.S. EPA, 2013, pp. 9–109 to 9–113), yet has concluded that based on the information available at this time, exposure indices that cumulate and differentially weight the higher hourly average concentrations while also including the ''mid-level'' values offer the most appropriate approach for use in developing response functions and comparing studies of O_3 effects on vegetation (U.S. EPA, 2013, p. 9–117). When considering the response of vegetation to O_3 exposures represented by the threshold (*e.g.,* SUM06) and non-threshold (*e.g.,* W126) indices, the ISA notes that ''the W126 metric does not have a cut-off in the weighting scheme as does SUM06 and thus it includes consideration of potentially damaging exposures below 60 ppb'' and that ''[t]he W126 metric also adds increasing weight to hourly concentrations from about 40 ppb to about 100 ppb'' (U.S. EPA, 2013, p. 9–104). This aspect of W126 is one way it differs from cut-off metrics such as the SUM06 where all concentrations above 60 ppb are treated equally and is identified by the ISA as ''an important feature of the W126 since as hourly concentrations become higher, they become increasingly likely to overwhelm plant defenses and are known to be more detrimental to vegetation'' (U.S. EPA, 2013, p. 9–104). Further, we note the concurrence by CASAC with the EPA's focus on the W126 exposure index, as noted above.

Some commenters also raised concerns regarding the sensitivity of vegetation in desert areas where plants take in ambient air during nighttime rather than daylight hours, such that little exposure occurs from 8 a.m. to 8 p.m., stating that the W126 index as defined by the EPA to cumulate hourly O_3 from 8 a.m. to 8 p.m. may result in an overly stringent exposure level in areas with such vegetation. The EPA recognizes that plants, such as cacti, that commonly occur in desert systems exhibit a particular type of metabolism (referred to as CAM photosynthesis) such that they only open their stomata at night (U.S. EPA, 2013, p. 9–109). We note, however, that few if any O_3 exposure studies of these species are available [203] to further inform our characterization of these species' responses to O_3, and we have no basis on which to conclude that an exposure level based on the studied species and a daylight exposure metric would be overly or underly stringent in areas where only species utilizing CAM photosynthesis occur. As summarized above, the CASAC advice concurred with the use of an 8am to 8pm diurnal period for the W126 exposure index. Thus, we conclude that for our purposes in this review the focus on daylight hours is appropriate. Our use of the W126 index in this review has been for purposes of characterizing the potential harm and conversely the potential protection that might be afforded from the well-characterized effects of O_3 on vegetation, while recognizing associated uncertainties and limitations. We note that different ecosystems across the U.S. will be expected to be of varying sensitivities with regard to the effects of O_3. For example, large water bodies without vegetation extending above the water's surface would be expected to be less sensitive than forests of sensitive species. The EPA notes, however, that the NAAQS are set with applicability to all ambient air in the U.S., such that the secondary O_3 standard provides protection in areas across the U.S. regardless of site-specific aspects of vegetation sensitivity to O_3. In considering the evidence on O_3 and associated welfare effects, we recognize variability in sensitivity that may relate to a number of factors, as discussed in the ISA (U.S. EPA, 2013, section 9.4.8). This variability is among the Administrator's considerations in setting the secondary standard for O_3 that is requisite to protect public welfare against anticipated or known adverse effects.

Further, some commenters who agreed with a focus on the W126 exposure index also stated that the EPA's definition of the index for the daylight hours of 8 a.m. to 8 p.m. and a 3-month period was not appropriate, stating that derivation of the W126 metric should involve summing concentrations for all 24 hours in each day and all months in each year to avoid underestimating O_3 exposure that the commenters viewed as pertinent. Support for the EPA's definition of the W126 index, with which CASAC concurred (Frey, 2014c, p. iii), is based on the assessment of the evidence in the ISA (U.S. 2013, section 9.5.3.2) and the context for use of the W126 index in relating O_3 exposure to magnitude and/or extent of O_3 response. This context has a particular focus on growth effects for the purposes of judging the potential for public welfare impacts, as well as the level of protection, associated with different exposure circumstances. We note that the ISA stated there is a lack of information that would allow consideration of the extent to which nocturnal exposures that may be of interest occur (U.S. EPA, 2013, p. 9–109). Additionally, in our use of the W126 index, we are relying on E–R functions based on studies that were generally of 3-month duration and involved controlled exposures during the daylight period. Accordingly we have relied on the E–R function derived for 12-hour and 3-month W126 indices, as described in section IV.A.1 above. To apply these E–R functions to the W126 estimates derived using 24 hours-per-day index values would inaccurately represent the response observed in the study (producing an overestimate). Similarly, with regard to the 3-month duration, ''[d]espite the possibility that plants may be exposed to ambient O_3 longer than 3 months in some locations, there is generally a lack of exposure experiments conducted for longer than

[202] For example, we note that among the 11 species for which robust E–R functions have been established for O_3 effects on tree seedling growth, the sensitivity of ponderosa pine, a species occurring in arid and high altitude regions of the western U.S., is similar to the median (U.S. EPA, 2014c, Table 5C–1).

[203] No O_3 exposure studies on cacti or other species that utilize CAM photosynthesis are reported in the ISA (U.S. EPA, 2013).

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3 months'' (U.S. EPA, 2014c, p. 9–112). Thus, in consideration of the lack of support in the current evidence for characterizing exposure for purposes of estimating RBL based on cumulative exposures derived from a combination of daytime and nighttime exposures and consideration of year-round O_3 concentrations across the U.S., we disagree with the commenters' view of the appropriateness of using an exposure index based on 24-hour, year-round O_3 concentrations.

The commenters supporting the use of the W126 exposure index were divided with regard to whether the EPA should focus on an annual index or one averaged over three years. Some of the commenters indicating support for the EPA's proposed focus on a 3-year average W126 index stated that this was appropriate in light of the wide variations in W126 index values that can occur on a year-to-year basis as a result of the natural variation of climatic conditions that have a direct impact on O_3 formation; in their view, these factors are mitigated by use of a 3-yr average, which thus provides ''stability'' in the assessment dampening out the natural variation of climatic conditions that have a direct impact on O_3 formation. Others noted that use of a 3-year average may be supported as matter of policy. We generally concur with the relevance of these points, among others, to a focus on the 3-year average W126. Other commenters expressed the view that the EPA should focus on an annual W126 index, generally making these comments in the context of expressing their support for a secondary standard with a W126 form. These commenters variously cited CASAC advice and its rationale for preferring a single year W126 form, stated that vegetation damage occurs on an annual basis, and/or questioned the EPA's statements of greater confidence in conclusions as to O_3 impacts based on a 3-year average exposure metric.

The EPA agrees with commenters that, as discussed in the PA and the proposal, depending on the exposure conditions, O_3 can contribute to measurable effects on vegetation in a single year. We additionally recognize that, as described in the PA and proposal, there is generally a greater significance for effects associated with multiple-year exposures. The proposal described a number of considerations raised in the PA as influencing the Administrator's decision to focus on a 3-year average W126 index (79 FR 75347, December 17, 2014). These included, among others, the observation of a greater significance for effects associated with multiple-year exposures, and the uncertainties associated with consideration of annual effects relative to multiple-year effects.

Further, we note that among the judgments contributing to the Administrator's decision on the level of protection appropriate for the secondary standard are judgments regarding the weight to place on the evidence of specific vegetation-related effects estimated to result across a range of cumulative seasonal concentration-weighted O_3 exposures and judgments on the extent to which such effects in such areas may be considered adverse to public welfare (79 FR 75312, December 17, 2014). Thus, conclusions regarding the extent to which the size and/or prevalence of effects on vegetation in a single year and any ramifications for future years represent an adverse effect to the public welfare, conclusions that are also inherently linked to overall magnitudes of exposures, are dependent on the Administrator's judgment. Accordingly, the decision regarding the need to focus on a 1-year or 3-year W126 index value is also a judgment of the Administrator, informed by the evidence, staff evaluations and advice from CASAC, as described in section IV.C.3 below.

d. Form and Averaging Time

In considering comments received on the proposed form for the revised standard, the EPA first notes the advice and comments from the CASAC, received in its review of the second draft PA. Similar to its advice in the last review, the CASAC recommended ''establishing a revised form of the secondary standard to be the biologically relevant W126 index'' (Frey, 2014c, p. iii). With regard to its reasons for this view, the CASAC cites the PA in stating that it ''concurs with the justification in [section 5.7] that the form of the standard should be changed from the current 8-hr form to the cumulative W126 index'' (Frey, 2014c, p. 12). In addressing specific aspects of this index, the CASAC concurred with the EPA's focus on the 3-month period with the highest index value and further states that ''[a]ccumulation over the 08:00 a.m.–08:00 p.m. daytime 12-hour period is a scientifically acceptable and recommended means of generalizing across latitudes and seasons'' (Frey, 2014c, p. 13). As section 5.7 of the PA discusses the W126 index in the context of the support in the evidence for use of the W126 exposure index for assessing impacts of O_3 on vegetation and the extent of protection from such impacts, we interpret CASAC's statement on this point to indicate that the basis for CASAC's view with regard to the form for the secondary standard relates to the appropriateness of the W126 exposure index for those assessment purposes.[204] [205]

The public comments on the form for a revised secondary standard were divided. Most of the state and local environmental agencies or governments, and all of the tribal agencies and organizations that provided comments on the form for the secondary standard concurred with the EPA's proposed decision, as did the industry commenters. These commenters generally indicated agreement with the rationale provided in the proposal that drew from the EPA analyses of recent air quality data examining relationships at sites across the U.S. between values of the fourth-high metric (the current design value) and values of a 3-year average W126-based metric, stating that this analysis showed that a standard in the form of the fourth-high metric, as proposed, can provide air quality consistent with or below the range of 3-year W126 exposure index values identified in the proposal. Some commenters additionally stated that the choice of form was a policy decision for the EPA and that little or no additional protection of public welfare would be gained by adopting a W126-based form. Some of these commenters provided analyses of data for their state or region that further supported this view. As

[204] Section 5.7 of the PA states that ''the evidence continues to provide a strong basis for concluding that it is appropriate to judge impacts of O_3 on vegetation, related effects and services, and the level of public welfare protection achieved, using a cumulative, seasonal exposure metric, such as the W126-based metric,'' references the support of CASAC for a W126-based secondary standard, and then concludes that ''based on the consistent and well-established evidence described above, . . . the most appropriate and biologically relevant way to relate O_3 exposure to plant growth, and to determine what would be adequate protection for public welfare effects attributable to the presence of O_3 in the ambient air, is to characterize exposures in terms of a cumulative seasonal form, and in particular the W126 metric'' (U.S. EPA, 2014c, p. 5–78).

[205] The CASAC also mentioned its support for revising the secondary standard to a W126 index-based form in its review of Chapter 6 of the second draft PA (Frey, 2014c, p. 13). Similar to section 5.7, in that chapter of the PA staff concluded that ''specific features associated with the W126 index still make it the most appropriate and biologically relevant cumulative concentration-weighted form for use in the context of the secondary O3 NAAQS review'' (U.S. EPA, 2014c, p. 6–5) and also concluded that ''it is appropriate to consider a revised secondary standard in terms of the cumulative, seasonal, concentration-weighted form, the W126 index'' (U.S. EPA, 2014c, p. 6–57).

[206] The term design value is commonly used to refer to the metric for the standard. Consistent with the summary in section I.D above, a design value is the statistic that describes the air quality of a given location in terms of the indicator, form and averaging time of the standard such that it can then be compared to the level of the standard.

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described in section IV.C.3 below, the EPA generally agrees with these commenters.

Some commenters, including a regional organization of state agencies and two groups of environmental organizations, submitted comments recommending revision of the standard to a cumulative, seasonal form based on the W126 index. In support of their position, these commenters generally cited CASAC advice, variously additionally indicating their view that the standard form should be a metric described as biologically relevant, and that the existing form, with a level in the proposed range, would not provide adequate ecosystem protection. Some commenters additionally suggested that the EPA cannot lawfully retain the form and averaging time that were initially established for purposes of the primary standard when the EPA has identified the W126 index as a metric appropriate for judging vegetation-related effects on public welfare. With regard to the EPA air quality analyses, summarized in the proposal, of the W126 index values at sites where O_3 concentrations met different levels of fourth-high metric, some of these commenters stated that the analyses showed widespread variation in W126 values for each fourth-high metric examined. Further, some commenters disagreed with the EPA that the analyses indicated that a revised standard level within the proposed range would be expected to limit W126 exposures in the future to the extent suggested by the analyses of data from the past.

We agree with public commenters and CASAC regarding the appropriateness of the W126 index (the sum of hourly concentrations over a specified period) as a biologically relevant metric for assessing exposures of concern for vegetation-related public welfare effects, as discussed in the proposal, PA and ISA. Accordingly, we agree that this metric is appropriate for use in considering the protection that might be expected to be afforded by potential alternative secondary standards, as discussed in section IV.C.2.c above. We disagree with commenters, however, that use of the W126 metric for this purpose dictates that we must establish a secondary standard with a W126 index form.

In support of this position, we note the common use, in assessments conducted for NAAQS reviews, of exposure metrics that differ in a variety of ways from the ambient air concentration metrics of those standards.[206] Across reviews for the various NAAQS pollutants, we have used a variety of exposure metrics to evaluate the protection afforded by the standards. These exposure metrics are based on the health or welfare effects evidence for the specific pollutant and commonly, in assessments for primary standards, on established exposure-response relationships or health-based benchmarks (doses or exposures of concern) for effects associated with specific exposure circumstances. Some examples of exposure metrics used to evaluate health impacts in primary standard reviews include the concentration of lead in blood of young children and a 5-minute exposure concentration for sulfur dioxide. In contrast, the health-based standards for these two pollutants are the 3-month concentration of lead in total suspended particles and the average across three years of the 99th percentile of 1-hour daily maximum concentration of sulfur dioxide in ambient air, respectively (73 FR 66964, November 12, 2008; 75 FR 35520, June 22, 2010). In somewhat similar manner, in the 2012 PM review, the EPA assessed the extent to which the existing 24-hour secondary standard for $PM_{2.5}$, expressed as a 24-hour concentration (of $PM_{2.5}$ mass per cubic meter of air) not to be exceeded more than once per year on average over three years, could provide the desired protection from effects on visibility in terms of the 90th percentile, 24-hour average $PM_{2.5}$ light extinction, averaged over three years, based on speciated $PM_{2.5}$ mass concentrations and relative humidity data (79 FR 3086, January 15, 2013). Additionally, in the case of the screening-level risk analyses in the 2008 review of the secondary standard for lead, concentrations of lead in soil, surface water and sediment were evaluated to assess the potential for welfare effects related to lead deposition from air, while the standard is expressed in terms of the concentration of lead in particles suspended in air (73 FR 67009, November 12, 2008).

Further, depending on the evidence base, some NAAQS reviews may consider multiple exposure metrics in assessing risks associated with a particular pollutant in ambient air in order to judge the adequacy of an existing standard in providing the required level of protection. And a standard with an averaging time of one duration may provide protection against effects elicited by exposures of appreciably shorter or longer durations. For example, in the current review of the primary O_3 standard, as described in section II above, we have considered the potential for effects associated with both short- and long-term exposures and concluded, based on a combination of air quality and risk analyses and the health effects evidence, that the existing standard with its short (8-hour) averaging time provides control of both the long and short term exposures (*e.g.,* from one hour to months or years) that may be of concern to public health. Similarly, during the 1996 review of the NO_2 primary standard, while health effects were recognized to result from both long-term and short-term exposures to NO_2, the primary standard, which was a long-term (annual) standard, was concluded to provide the requisite protection against both long- and short-term exposures (61 FR 52852, Oct 8 1996). In the subsequent review of the NO_2 primary standard in which the available air quality information indicated that the annual standard was not providing the needed control of the shorter term exposures, an additional short-term standard was established (75 FR 6474, February 9, 2010).

Thus, we note that different metrics may logically, reasonably, and for technically sound reasons, be used in assessing exposures of concern or characterizing risk as compared to the metric of the standard which is used to control air quality to provide the desired degree of protection. That is, exposure metrics are used to assess the likely occurrence and/or frequency and extent of effects under different air quality conditions, while the air quality standards are intended to control air quality to the extent requisite to protect from the occurrence of public health or welfare effects judged to be adverse. In this review of the secondary standard for O_3, the EPA agrees that, for the reasons summarized in section IV.A.1 above and described in the ISA, the W126 index—and not an 8-hour daily maximum concentration that has relevance in human health risk characterization, as described in section II above—is the appropriate metric for assessing exposures of concern for vegetation, characterizing risk to public welfare, and evaluating what air quality conditions might provide the desired degree of public welfare protection. We disagree, however, that the secondary standard must be established using that same metric.

Moreover, we note that the CAA does not require that the secondary O_3 standard be established in a specific

[206] The term design value is commonly used to refer to the metric for the standard. Consistent with the summary in section I.D above, a design value is the statistic that describes the air quality of a given location in terms of the indicator, form and averaging time of the standard such that it can then be compared to the level of the standard.

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form. Section 109(b)(2) provides only that any secondary NAAQS ''shall specify a level of air quality the attainment and maintenance of which in the judgment of the Administrator, based on [the air quality] criteria, is requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air. . . . [S]econdary standards may be revised in the same manner as promulgated.'' The EPA interprets this provision to leave it considerable discretion to determine whether a particular form is appropriate, in combination with the other aspects of the standard (averaging time, level and indicator), for specifying the air quality that provides the requisite protection, and to determine whether, once a standard has been established in a particular form, that form must be revised. Moreover, nothing in the Act or the relevant case law precludes the EPA from establishing a secondary standard equivalent to the primary standard in some or all respects, as long as the Agency has engaged in reasoned decision-making.[207]

With regard to the commenter's emphasis on advice from CASAC on the form of the secondary standard, the EPA agrees with the importance of giving such advice careful consideration. The EPA further notes, however, that the Administrator is not legally precluded from departing from CASAC's recommendations, when she has provided an explanation of the reasons for such differences.[208] Accordingly, in reaching conclusions on the revised secondary standard in this review, the Administrator has given careful consideration to the CASAC advice in this review and, when she has differed from CASAC recommendations, she has fully explained the reasons and judgments that led her to a different conclusion, as described in section IV.C.3 below.

In disagreeing with the EPA's conclusions drawn from analyses of recent air quality data on the extent to which cumulative seasonal exposures might be limited to within or below the identified 3-year average W126 index values by controlling air quality using different values for the fourth-high metric, one group of environmental organizations emphasized the range of W126 index values that occur at monitors with concentrations at or below specific values for the fourth-high metric. For monitor observations for which the fourth-high metric was at or below 70 ppb, this commenter group stated that some sites have 3-year average W126 index values above 17 ppm-hrs and noted a maximum 3-year W126 index value of 19.1 ppm-hrs, while additionally noting occurrences of other W126 values above the CASAC range of 7 to 15 ppm-hrs. This commenter additionally stated that the air quality data ''do not support a claim of congruence'' between the fourth-high and W126 metrics (*e.g.,* ALA et al., p. 196), that there is no basis for concluding that there is some fundamental underlying relationship that assures meeting the fourth-high metric will mean meeting any of the W126 options, and that the relationship between the metrics is non-linear with significant spread in the data (citing visual inspection of a graph).

The EPA does not agree with the commenter's statements regarding the relationship between the two metrics.[209] We have not, as stated by the commenter, claimed there to be ''congruence'' between the two metrics (*e.g.,* ALA et al., p. 196), or that the two metrics coincide exactly. Rather, at any location, values of both metrics are a reflection of the temporal distribution of hourly O_3 concentrations across the year and both vary in response to changes in that distribution. While the EPA's air quality analysis shows that the specific relationship differs among individual sites, it documents an overall strong, positive, non-linear relationship between the two metrics (Wells, 2014a, p. 6, Figures 5a and 5b; Wells, 2015b). Further, this analysis finds the amount of year-to-year variability in the two metrics tended to decrease over time with decreasing O_3 concentrations, especially for the W126 metric, as described in section IV.E.4 of the proposal (Wells, 2014a; Wells, 2015b).

With regard to the highest 3-year average W126 exposure index values that might reasonably be expected in the future in areas where a revised standard with a fourth-high form is met, we disagree with the commenters as to the significance of the W126 index value of 19.1 ppm-hrs in the 13-year dataset. This value, for a site during the period 2006–2008, is the only occurrence at or above 19 ppm-hrs in the nearly 4000 3-year W126 index values—across the 11 3-year periods extending back in time from 2013—for which the fourth-high metric for the same monitor location is at or below 70 ppb. This is clearly an isolated occurrence.

In considering this comment, we have expanded the technical memorandum that was available at the time of proposal (Wells, 2014a). The expanded memorandum describes the same air quality analyses for 3-year periods from 2001 through 2013 as the 2014 memorandum, and includes additional summary tables for all 3-year periods from 2001 through 2013 as well as tables for the most recent period, 2011–2013 (Wells, 2015b). After the 3-year W126 index value of 19 ppm-hrs, the next three highest 3-year average W126 index values, which are the only other such values above 17 ppm-hrs in the 13-year dataset, and which also occur during periods in the past, round to 18 ppm-hrs (Wells, 2015b). Additionally, we note that reductions in the fourth-high metric over the 13-year period analyzed are strongly associated with reductions in the cumulative W126 index (Wells, 2014a, Figure 11, Table 6; Wells, 2015b). Specifically, the regression analysis of changes in W126 index between the 2001–2003 period and the 2011–2013 period with changes in the fourth-high metric across the same periods indicates a fairly linear and positive relationship between reductions of the two types of metrics, with, on average, a change of approximately 0.7 ppm-hr in the W126 index per ppb change in the fourth-high metric value. From this information we conclude that W126 exposures above 17 ppm-hrs at sites for which the fourth-high metric is at or below 70 ppb would be expected to continue to be rare in the future, particularly as steps are taken to meet a 70 ppb standard.

With regard to the comment that the relationship between the two metrics varies across locations, the EPA agrees that there is variation in cumulative seasonal O_3 exposure (in terms of a 3-year average W126 index) among locations that are at or below the same fourth-high metric. As noted in the proposal, the analysis illustrates this variation, with the locations in the West and Southwest NOAA climatic regions tending to have the highest cumulative seasonal exposures for the same fourth-high metric value. In considering expectations for the future in light of this observation, however, we note that

[207] In fact, the D.C. Circuit has upheld secondary NAAQS that were identical to the corresponding primary standard for the pollutant (*e.g., ATA III,* 283 F.3d at 375, 380 [D.C. Cir. 2002, upholding secondary standards for $PM_{2.5}$ and O_3 that were identical to primary standards]).

[208] See CAA sections 307(d)(3) and 307(d)(6)(A); see also *Mississippi* v. *EPA,* 744 F.3d 1334, 1354 (D.C. Cir. 2013) (''Although EPA is not bound by CASAC's recommendations, it must fully explain its reasons for any departure from them'').

[209] The EPA additionally notes that commenters contradict their own assertion when, after stating their view that no relationship exists between the 4th high and W126 metrics, the commenter then states that there is a nonlinear relationship and yet then relies on a predicted *linear* relationship to estimate W126 values occurring when air quality meets different values for the 4th high metric at 11 national parks.

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the regional regressions of reductions in W126 metric with reductions in the fourth-high metric indicate that the Southwest and West regions, which had the greatest potential for sites having 3-year W126 index values greater than the various W126 values of interest when fourth-high values are less than or equal to the various fourth-high metric values of interest, also exhibited the greatest reduction in the W126 index values per unit reduction in the fourth-high values (Wells, 2015b). Thus, in considering the potential for occurrences of values above 17 ppm-hrs in the future in areas that meet a fourth-high of 70 ppb, the EPA notes that the analysis indicates that those areas that exhibited the greatest likelihood of occurrence of a 3-year W126 index above a level of interest (*e.g.,* the commenters' example in the Southwest region of a value of 19.1 ppm-hrs [2006–2008] in comparison to the W126 level of 17 ppm-hrs) also exhibit the greatest improvement in W126 per unit decrease in fourth-high metric.[210] It is expected that future control programs designed to meet a standard with a fourth-high form would provide similar improvements in terms of the W126 metric.

As part of their rationale in support of revising the current form and averaging time, one commenter pointed to the regional variation in the highest W126 index values expected at sites that just meet a fourth-high metric of 70 ppb, based on the EPA's analysis of recent air quality data available at the time of the proposal (Wells, 2014a). This commenter observed that, while in some U.S. regions, locations that meet a potential alternative standard with the current form and a level of 70 ppb also have 3-year average W126 index values no higher than 17 ppm-hrs, the highest W126 index values in other parts of the country are lower. As a result, the commenter concluded that such a standard would result in regionally differing levels of welfare protection. The commenter additionally states that, for extreme values, a W126 form for the secondary standard would also offer different levels of protection, although with the primary standard setting the upper boundary for such values.

The EPA recognizes that a standard with the current form might be expected to result in regionally differing distributions of W126 exposure index values (including different maximum values) depending on precursor sources, local meteorology, and patterns of O_3 formation. Variation in exposures is to be expected with any standard (secondary or primary) of any form. In fact, variation in exposures and any associated variation in welfare or health risk is generally an inherent aspect of the Administrator's judgment on a specific standard, and any associated variation in welfare or health protection may play a role in the Administrator's judgment with regard to public welfare or public health protection objectives for a national standard. In considering the comment, however, we have focused only on the extent to which the commenter's conclusion that a secondary standard of the current form and averaging time would provide regionally varying welfare protection might indicate that the specified air quality is more (or less) than necessary to achieve the purposes of the standard. In so doing, we additionally respond to a separate comment that the EPA needs to address how the revised secondary standard is neither more or less than necessary to protect the public welfare.

The CAA requirement in establishing a standard is that it be set at a level of air quality that is requisite, meaning ''sufficient, but not more than necessary'' (*Whitman* v. *American Trucking Ass'ns,* 531 U.S. 457, 473 [2001]). We note that the air quality that is specified by the revised primary standard has been concluded to be ''necessary'' and it may be reasonable and appropriate to consider the stringency of the secondary standard in light of what is identified as ''necessary'' for the primary standard. The EPA considered the stringency of the O_3 secondary standard in this way in the 1979 decision (44 FR 8211, February 8, 1979), which was upheld in subsequent litigation (*API v Costle,* 665 F.2d 1176 [D.C. Cir. 1991]). We note that, in similar manner, the commenter considered public welfare protection that might be afforded by the primary standard in noting that the primary standard would be expected to provide welfare protection from extreme values.[211]

In addressing the remand of the 2008 secondary standard in this rulemaking, as discussed in section IV.C.2.e below, the EPA recognizes that it must explain the basis for concluding that the standard selected by the Administrator specifies air quality that will provide the degree of public welfare protection needed from the secondary standard (*Mississippi* v. *EPA,* 744 F.3d 1334, 1360–61 [D.C. Cir. 2013]). In this review, the Administrator describes the degree or level of public welfare protection needed from the secondary standard and fully explains the basis for concluding that the standard selected specifies air quality that will provide that degree of protection. If the Administrator concludes that the level of air quality specified by the primary standard would provide sufficient protection against known or anticipated adverse public welfare effects, the EPA believes that a secondary standard with that indicator, level, form and averaging time could be considered to be requisite. If the level of air quality that areas will need to achieve or maintain for purposes of the primary standard also provides a level of air quality that is adequate to provide the level of protection identified for the secondary standard, there would be little purpose in requiring the EPA to establish a less stringent secondary standard. For these reasons, the expectation of regionally differing cumulative exposures under a secondary standard of the current form and averaging time does not lead us to conclude that the air quality specified by such a standard would be more (or less) than necessary (and thus not requisite) for the desired level of public welfare protection.

e. Revisions to the Standard Level

Some comments specifically addressed the level for a revised secondary standard of the current form and averaging time. Of the comments that addressed this, some from states or industry groups generally supported a level within the proposed range, frequently specifying the upper end of the range (70 ppb), while comments

[210] Additionally, O_3 levels at any location are influenced by upwind precursor emissions, and many rural areas, including the site referenced by the commenter, are impacted by precursor emissions from upwind urban areas, such that as emissions are reduced to meet a revised standard in the upwind locations, reductions in those upwind emissions will contribute to reductions at the downwind sites (Wells, 2014a; ISA, pp. 3–129 to 3–133).

[211] As described earlier in this section, the EPA has also considered the air quality specified by one secondary standard in a decision on the need for a second secondary standard. In the decision not to adopt a second $PM_{2.5}$ secondary standard specific to visibility-related welfare effects, the Administrator, after describing the public welfare protection objective related to visibility effects, considered analyses that related air quality associated with the existing secondary standard to that expected for the proposed visibility-focused secondary standard. From these analyses, she concluded sufficient protection against visibility effects would be provided by the existing standard, and to the extent that the existing standard would provide more protection than had been her objective for such effects, adoption of a second secondary standard focused on visibility would not change that result (78 FR 3227–3228, January 15, 2013). This decision responded to a court remand of the prior EPA decision that visibility protection would be afforded by a secondary standard set equal to the primary standard based on the court's conclusion that the EPA had not adequately described the Administrator's objectives for visibility-related public welfare protection under the standard (*American Farm Bureau,* 559 F.3d at 530–531).

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from tribes and tribal organizations, and a few others, recommended a level no higher than 65 ppb. The Administrator has considered such comments in reaching her decision on the appropriate revisions to the standard, described in section IV.C.3. Detailed aspects of these comments are discussed in the Response to Comments document.

f. 2013 Court Remand and Levels of Protection

Both industry groups and a group of environmental advocacy organizations submitted comments on the extent to which the proposal addressed the July 2013 remand of the secondary standard by the U.S. Court of Appeals for the D.C. Circuit. The former generally concluded that the proposal had adequately addressed the remand, while the latter expressed the view that the EPA had failed to comply with the court's remand because it had failed to identify the target levels of vegetation protection for which the proposed range of standards would provide the requisite protection, claiming that the identified W126 index range of 13–17 ppm-hrs was not based on a proposed level of protection against biomass loss, carbon storage loss, or foliar injury that the EPA had identified as requisite for public welfare.

We agree with the comments that state that we have addressed the court's remand. More specifically, with this rulemaking, including today's decision and the Administrator's conclusions described in section IV.C.3 below, the EPA has fully addressed the remand of the 2008 secondary O_3 standard. In *Mississippi* v. *EPA,* the D.C. Circuit remanded the 2008 secondary O_3 standard to the EPA for reconsideration because it had not adequately explained why that standard provided the requisite public welfare protection. 744 F.3d 1334, 1360–61 (D.C. Cir. 2013). In doing so, the court relied on the language of CAA section 109(b)(2), and the court's prior decision, *American Farm Bureau Federation* v. *EPA,* 559 F.3d 512, 528–32 (D.C. Cir. 2009), which came to the same conclusion for the 2006 secondary $PM_{2.5}$ standard. Both decisions recognize that the plain language of section 109(b)(2) requires the EPA to ''specify a level of air quality the maintenance of which . . . is requisite to protect the public welfare from any known or anticipated adverse effects'' (*Mississippi,* 744 F.3d at 1360 [citing *American Farm Bureau,* 559 F.3d at 530]). Further, explaining that it was insufficient for the EPA ''merely to compare the level of protection afforded by the primary standard to possible secondary standards and to find the two roughly equivalent'' (*Mississippi,* 744 F.3d at 1360), the court rejected the EPA's justification for setting the secondary standard equivalent to the primary standard because that justification was based on comparing the protection from the primary standard to that expected from one possible standard with a cumulative, seasonal form (21 ppm-hrs) without stating that such a cumulative seasonal standard would be requisite to protect welfare or explaining why that would be so. Because the EPA had ''failed to determine what level of protection was 'requisite to protect the public welfare'' (*Mississippi,* 744 F.3d at 1362), the court found that the EPA's rationale failed to satisfy the requirements of the Act.

Today's rulemaking both satisfies the requirements of section 109(b)(2) of the Act and addresses the issues raised in the court's remand. In this rulemaking, the Administrator has established a revised secondary standard that replaces the remanded 2008 secondary standard. In so doing, based on her consideration of the currently available evidence and quantitative exposure and air quality information, as well as advice from CASAC and input from public comments, the Administrator has described the requisite public welfare protection for the secondary standard and explained how the standard selected specifies air quality that will provide that protection. As explained in detail in IV.C.3 below, in this review the Administrator is describing the public welfare protection she finds requisite in terms of seedling RBL in the median species, which serves as a surrogate for a broader array of O_3 effects at the plant and ecosystem levels. This description of the desired protection sufficiently articulates the standard that the Administrator is using to evaluate welfare protection. Further, the Administrator has considered air quality analyses in determining how to achieve the air quality conditions associated with the desired protection. Based on these analyses, the Administrator is determining that revising the level of the secondary standard to 70 ppb, while retaining the current form, averaging time, and indicator, specifies a level of air quality that will provide the requisite public welfare protection.

To the extent the comments suggest that the EPA is required in establishing a standard to identify a precise and quantified level of public welfare protection that is requisite with respect to every potentially adverse public welfare impact (*e.g.,* visible foliar injury, crop yield loss) that is considered in establishing the standard, we disagree. While the D.C. Circuit has required the EPA to ''qualitatively describe the standard governing its selection of particular NAAQS,'' it has expressly ''rejected the notion that the Agency must establish a measure of the risk to safety it considers adequate to protect public health every time it establishes a NAAQS'' (*ATA III,* 283 F.3d at 369 [internal marks and citations omitted]). That is, the EPA must ''engage in reasoned decision-making,'' but is not required to ''definitively identify pollutant levels below which risks to public health are negligible'' (*ATA III,* 283 F.3d at 370). This principle recognizes that the Act requires the EPA to establish NAAQS even when the risks or effects of a pollutant cannot be quantified or precisely identified because of scientific uncertainty concerning such effects at atmospheric concentrations (*ATA III,* 283 F.3d at 370). Though these decisions specifically address setting a primary standard under CAA section 109(b)(1), we believe the same principles apply to the parallel provision in section 109(b)(2) governing secondary standards. Accordingly, while the EPA recognizes that it must explain the basis for concluding that the standard selected by the Administrator specifies air quality that will provide the protection against adverse effects on public welfare needed from the secondary standard (*Mississippi* v. *EPA,* 744 F.3d 1334, 1360–61 [D.C. Cir. 2013]), the CAA does not require the EPA to precisely quantify the measure of protection that is necessary to protect the public welfare in establishing a secondary standard. In light of the Administrator's description of the desired public welfare protection in IV.C.3 below, which has both qualitative and quantitative components, the EPA is not required to further reduce this description to a precise, quantitative target level of vegetation protection. Moreover, nothing in the CAA or in case law requires the EPA to identify a target level of protection for any particular public welfare effect, such as vegetation effects, but rather leaves the Administrator discretion in judging how to describe the public welfare protection that she concludes is requisite. In IV.C.3 below, the Administrator explains her reasoning for giving primary focus to growth-related effects in describing the requisite welfare protection, rather than to other welfare effects such as foliar injury, for which there are more uncertainties and less predictability with respect to the severity of the effects that would be expected from varying O_3 exposures in the natural environment

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and the significance of the associated impacts to public welfare.

3. Administrator's Conclusions on Revision

In reaching her decision on the appropriate revisions to the secondary standard, the Administrator has drawn on (1) the ISA conclusions regarding the weight of the evidence for a range of welfare effects associated with O_3 in ambient air, quantitative findings regarding air quality and ecosystem exposures associated with such effects, and associated limitations and uncertainties; (2) staff evaluations in the PA of the evidence summarized in the ISA, the exposure/risk information developed in the WREA and analyses of air quality monitoring information; (3) additional air quality analyses of relationships between air quality metrics based on form and averaging time of the current standard and the W126 cumulative seasonal exposure index; (4) CASAC advice; and (5) consideration of public comments. After giving careful consideration to all of this information, the Administrator believes that the conclusions and policy judgments supporting her proposed decision remain valid.

The Administrator concludes it is appropriate to continue to use O_3 as the indicator for a secondary standard intended to address adverse effects to public welfare associated with exposure to O_3 alone and in combination with related photochemical oxidants. In this review, no alternatives to O_3 have been advanced as being a more appropriate surrogate for ambient photochemical oxidants. Advice from CASAC concurs with the appropriateness of retaining the current indicator. Thus, as is the case for the primary standard (discussed above in section II.C.1), the Administrator has decided to retain O_3 as the indicator for the secondary standard. In so doing, she recognizes that measures leading to reductions in ecosystem exposures to O_3 would also be expected to reduce exposures to other photochemical oxidants.

In her decision on the other elements of the standard, the Administrator has considered the body of evidence and information in a systematic fashion, giving appropriate consideration to the important findings of the ISA as to the effects of O_3 in ambient air that may present risks to the public welfare, measures of exposure best formulated for assessment of these effects, associated evidence regarding ecosystem exposures and air quality associated with such effects; judgments regarding the weight to place on strengths, limitations and uncertainties of this full body of information; and public welfare policy judgments on the appropriate degree of protection and the form and level of a revised standard that will provide such protection. In reaching her decision, the Administrator recognizes that the Act does not require that NAAQS be set at zero-risk or background levels, but rather at levels that reduce risk sufficiently to protect public welfare from known or anticipated adverse effects. In addition, we note that the elements of the standard (indicator, level, form, and averaging time) are considered together in assessing the protection provided by a new or revised standard, and the EPA's approach for considering the elements of a new or revised standard is part of the exercise of the judgment of the Administrator.

As an initial matter, the Administrator recognizes the robustness of the longstanding evidence, described in the ISA, of O_3 effects on vegetation and associated terrestrial ecosystems. The newly available studies and analyses have strengthened the evidence for the current review that provides the foundation for the Administrator's consideration of O_3 effects, associated public welfare protection objectives, and the revisions to the current standard needed to achieve those objectives. In light of the extensive evidence base in this regard, the Administrator focuses on protection against adverse public welfare effects of O_3 related effects on vegetation. In so doing, she takes note of effects that compromise plant function and productivity, with associated effects on ecosystems. She is particularly concerned about such effects in natural ecosystems, such as those in areas with protection designated by Congress for current and future generations, as well as areas similarly set aside by states, tribes and public interest groups with the intention of providing similar benefits to the public welfare. She additionally recognizes that providing protection for this purpose will also provide a level of protection for other vegetation that is used by the public and potentially affected by O_3 including timber, produce grown for consumption and horticultural plants used for landscaping.

A central issue in this review of the secondary standard, as in the last review (completed in 2008), has been consideration of the role for a cumulative seasonal exposure index. In the last review, the Administrator proposed such an index as one of two options for the form of a revised standard. The Administrator's decision in that review was to retain the existing form and averaging time, while revising the standard level to provide the desired level of protection. As described in section IV.A above, this decision was remanded to the EPA in 2013 by the DC Circuit. In the current review, the ISA evaluates the evidence and concludes that, among the approaches investigated, quantifying exposure with a cumulative seasonal index best captures the aspects of exposure that relate to effects on vegetation, particularly those related to growth and yield. The PA considered this finding both in the context of assessing potential impacts, and, conversely, the protection from such impacts that might be realized, as well as in the context of using a cumulative seasonal exposure index as a form for the secondary standard. In the proposal, the Administrator focused on the former context, as an exposure index, while additionally soliciting comment on use of the index as the form for the revised standard. Advice from CASAC, all of which was received prior to the proposal, has largely emphasized the latter context, and that was also the focus of some comments.

In considering revisions to the secondary standard that will specify a level of air quality to provide the necessary public welfare protection, the Administrator focuses on use of a cumulative seasonal exposure index, including specifically the W126 index as defined in the proposal, for assessing exposure, both for making judgments with regard to the potential harm to public welfare posed by conditions allowed by various levels of air quality and for making the associated judgments regarding the appropriate degree of protection against such potential harm. In so doing, the Administrator takes note of the conclusions in the ISA and PA, with which the CASAC concurred, that, based on the currently available evidence, a cumulative seasonal concentration-weighted index best captures the aspects of ecosystem exposure to O_3 in ambient air that impact vegetation. In considering the public comments in this area, she notes the broad support for use of such a metric as an exposure index, with many additionally supporting its use as the form for a revised standard, in light of CASAC advice on that point. Thus, based on the substantial support in the evidence and CASAC advice, and in consideration of public comments, the Administrator concludes that it is appropriate to use such a cumulative seasonal concentration-weighted index for purposes of assessing the potential

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public welfare risks, and similarly, for assessing the potential protection achieved against such risks on a national scale.

The Administrator has considered conclusions of the ISA and PA, as well as advice from CASAC and public comments, regarding different cumulative, concentration-weighted metrics, and different temporal definitions of aspects of these metrics. The Administrator takes note of the PA conclusions in support of the W126 exposure index, recognized by the ISA for its strength in weighting potentially damaging O_3 concentrations that contributes to the advantages it offers over other weighted cumulative indices. With regard to the relevant definitions for the temporal aspects of this index, conclusions in the ISA and PA, and such considerations in the last review, have led to a focus on a maximum 3-month, 12-hour index, defined by the 3-consecutive-month period within the O_3 season with the maximum sum of W126-weighted hourly O_3 concentrations during the period from 8:00 a.m. to 8:00 p.m. each day (as explained in section IV.A.1.c above). The Administrator takes note of the support in the ISA and PA, as well as CASAC recommendations for consideration of the W126 index defined in this way. While recognizing that no one definition of an exposure metric used for the assessment of protection for multiple effects at a national scale will be exactly tailored to every species or each vegetation type, ecosystem and region of the country, as discussed in section IV.C.2 above, the Administrator judges that on balance, a W126 index derived in this way, and averaged over three years, as discussed below, will be appropriate for such purposes.

In considering the appropriate exposure index to facilitate assessment of the level of protection afforded to the public welfare by alternative secondary standards in the proposal, the Administrator concluded that a 3-year average W126 index was appropriate for these purposes. A number of considerations raised in the PA influenced the Administrator's conclusion at the time of proposal, in combination with public welfare judgments regarding the weight to place on the evidence of specific vegetation-related effects estimated to result across a range of cumulative seasonal concentration-weighted O_3 exposures and judgments on the extent to which such effects in such areas may be considered adverse to public welfare (79 FR 76347, 75312, December 17, 2014,). Some comments were received from the public on this aspect of the proposed decision, as discussed in section IV.C.2 above, and have been considered in the conclusions reached here.

The Administrator continues to place weight on key aspects raised in the PA and summarized in the proposal on the appropriateness of considering a 3-year average index. The Administrator notes the PA consideration of the potential for multiple consecutive years of critical O_3 exposures to result in larger impacts on forested areas than intermittent occurrences of such exposures due to the potential for compounding effects on tree growth. The Administrator additionally notes the evidence, as considered in the PA and summarized in the proposal, for some perennial species of some effects associated with a single year's exposure of a critical magnitude that may have the potential for some ''carry over'' of effects on plant growth or reproduction in the subsequent season. Further, the Administrator notes the occurrence of visible foliar injury and growth or yield loss in annual plants or crops associated with exposures of a critical magnitude. While the Administrator appreciates that the scientific evidence documents the effects on vegetation resulting from individual growing season exposures of specific magnitude, including those that can affect the vegetation in subsequent years, she is also mindful, both of the strengths and limitations of the evidence, and of the information on which to base her judgments with regard to adversity of effects on the public welfare. The Administrator also recognizes uncertainties associated with interpretation of the public welfare significance of effects resulting from a single-year exposure, and that the public welfare significance of effects associated with multiple years of critical exposures are potentially greater than those associated with a single year of such exposure.

As she did for the proposal, the Administrator has considered advice from CASAC in this area, including the CASAC comments that it favors a W126-based secondary standard with a single year form, that its recommended range of levels relates to such a form, and that a lower range (*e.g.,* with 13 ppm-hrs at the upper end) would pertain to a 3-year form. The Administrator also notes CASAC's recognition that her decision on use of a 3-year average over a single-year W126 index may be a matter of policy. While recognizing the potential for effects on vegetation associated with a single-year exposure, the Administrator concludes that use of a 3-year average metric can address the potential for adverse effects to public welfare that may relate to shorter exposure periods, including a single year.

While the Administrator recognizes the scientific information and interpretations, as well as CASAC advice, with regard to a single-year exposure index, she also takes note of uncertainties associated with judging the degree of vegetation impacts for annual effects that would be adverse to public welfare. Even in the case of annual crops, the assessment of public welfare significance is unclear for the reasons discussed below related to agricultural practices. The Administrator is also mindful of the variability in ambient air O_3 concentrations from year to year, as well as year-to-year variability in environmental factors, including rainfall and other meteorological factors, that influence the occurrence and magnitude of O_3-related effects in any year, and contribute uncertainties to interpretation of the potential for harm to public welfare over the longer term. As noted above, the Administrator also recognizes that the public welfare significance of effects associated with multiple years of critical exposures are potentially greater than those associated with a single year of such exposure. Based on all of these considerations, the Administrator recognizes greater confidence in judgments related to public welfare impacts based on a 3-year average metric. Accordingly, the considerations identified here lead the Administrator to conclude it is appropriate to use an index averaged across three years for judging public welfare protection afforded by a revised secondary standard.

In reaching a conclusion on the amount of public welfare protection from the presence of O_3 in ambient air that is appropriate to be afforded by a revised secondary standard, the Administrator has given particular consideration to the following: (1) The nature and degree of effects of O_3 on vegetation, including her judgments as to what constitutes an adverse effect to the public welfare; (2) the strengths and limitations of the available and relevant information; (3) comments from the public on the Administrator's proposed decision, including comments related to identification of a target level of protection; and (4) CASAC's views regarding the strength of the evidence and its adequacy to inform judgments on public welfare protection. The Administrator recognizes that such judgments include judgments about the interpretation of the evidence and other information, such as the quantitative analyses of air quality monitoring,

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exposure and risk. She also recognizes that such judgments should neither overstate nor understate the strengths and limitations of the evidence and information nor the appropriate inferences to be drawn as to risks to public welfare. The CAA does not require that a secondary standard be protective of all effects associated with a pollutant in the ambient air but rather those known or anticipated effects judged adverse to the public welfare (as described in section IV.A.3 above). The Administrator additionally recognizes that the choice of the appropriate level of protection is a public welfare policy judgment entrusted to the Administrator under the CAA taking into account both the available evidence and the uncertainties.

The Administrator finds the coherence and strength of the weight of evidence concerning effects on vegetation from the large body of available literature compelling. The currently available evidence addresses a broad array of O_3-induced effects on a variety of tree species across a range of growth stages (*i.e.,* seedlings, saplings and mature trees) using diverse field-based (*e.g.,* free air, gradient and ambient) and OTC exposure methods. The Administrator gives particular attention to the effects related to native tree growth and productivity, recognizing their relationship to a range of ecosystem services, including forest and forest community composition. She is also mindful of the significance of community composition changes, particularly in protected areas, such as Class I areas. At the same time, she recognizes, while the evidence strongly supports conclusions regarding O_3 impacts on growth and the evidence showing effects on tree seedlings, as well as on older trees, there are limitations in our ability to predict impacts in the environment or to estimate air quality or exposures that will avoid such impacts. Such limitations relate to the variability of environmental factors or characteristics that can influence the extent of O_3 effects.

In recognition of the CASAC advice and the potential for adverse public welfare effects, the Administrator has considered the nature and degree of effects of O_3 on the public welfare. In so doing, the Administrator recognizes that the significance to the public welfare of O_3-induced effects on sensitive vegetation growing within the U.S. can vary, depending on the nature of the effect, the intended use of the sensitive plants or ecosystems, and the types of environments in which the sensitive vegetation and ecosystems are located. Any given O_3-related effect on vegetation and ecosystems (*e.g.,* biomass loss, visible foliar injury), therefore, may be judged to have a different degree of impact on the public depending, for example, on whether that effect occurs in a Class I area, a residential or commercial setting, or elsewhere. The Administrator notes that such a distinction is supported by CASAC advice in this review. In her judgment, like those of the Administrator in the last review, it is appropriate that this variation in the significance of O_3-related vegetation effects should be taken into consideration in making judgments with regard to the level of ambient O_3 concentrations that is requisite to protect the public welfare from any known or anticipated adverse effects. As a result, the Administrator concludes that of those known and anticipated O_3-related vegetation and ecosystem effects identified and discussed in this notice, particular significance should be ascribed to those that may occur on sensitive species that are known to or are likely to occur in federally protected areas such as Class I areas or on lands set aside by states, tribes and public interest groups to provide similar benefits to the public welfare, for residents on those lands, as well as visitors to those areas.

Likewise, the Administrator also notes that less protection related to growth effects may be called for in the case of other types of vegetation or vegetation associated with other uses or services. For example, the maintenance of adequate agricultural crop yields is extremely important to the public welfare and currently involves the application of intensive management practices. With respect to commercial production of commodities, the Administrator notes that judgments about the extent to which O_3-related effects on commercially managed vegetation are adverse from a public welfare perspective are particularly difficult to reach, given that the extensive management of such vegetation (which, as CASAC noted, may reduce yield variability) may also to some degree mitigate potential O_3-related effects. The management practices used on these lands are highly variable and are designed to achieve optimal yields, taking into consideration various environmental conditions. In addition, changes in yield of commercial crops and commercial commodities, such as timber, may affect producers and consumers differently, further complicating the question of assessing overall public welfare impacts. Thus, the Administrator concludes, while research on agricultural crop species remains useful in illuminating mechanisms of action and physiological processes, information from this sector on O_3-induced effects is considered less useful in informing judgments on what specific standard would provide the appropriate public welfare protection. In so doing, the Administrator notes that a standard revised to increase protection for forested ecosystems would also be expected to provide some increased protection for agricultural crops and other commercial commodities, such as timber.

The Administrator also recognizes that O_3-related effects on sensitive vegetation can occur in other areas that have not been afforded special federal or other protections, including effects on vegetation growing in managed city parks and residential or commercial settings, such as ornamentals used in urban/suburban landscaping or vegetation grown in land use categories involving commercial production of commodities, such as timber. For vegetation used for residential or commercial ornamental purposes, the Administrator believes that there is not adequate information at this time to establish a secondary standard based specifically on impairment of these categories of vegetation, but notes that a secondary standard revised to provide protection for sensitive natural vegetation and ecosystems would likely also provide some degree of protection for such vegetation.

Based on the above considerations, in identifying the appropriate level of protection for the secondary standard, the Administrator finds it appropriate to focus on sensitive trees and other native species known or anticipated to occur in protected areas such as Class I areas or on other lands set aside by the Congress, states, tribes and public interest groups to provide similar benefits to the public welfare, for residents on those lands, as well as visitors to those areas. In light of their public welfare significance, the Administrator gives particular weight to protecting such vegetation and ecosystems. Given the reasons for the special protection afforded such areas (identified in section I.A.3 above), she recognizes the importance of protecting these natural forests from O_3-induced impacts, including those related to O_3 effects on growth, and including those extending in scale from individual plants to the ecosystem. The Administrator also recognizes that the impacts identified for O_3 range from those for which the public welfare significance may be more easily judged, but for which quantitative relationships

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with O_3 in ambient air are less well established, such as impacts on forest community composition in protected wilderness areas, carbon storage and other important ecosystem services, to specific plant-level effects, such as growth impacts (in terms of RBL) in tree seedlings, for which our quantitative estimates are more robust.

For considering the appropriate public welfare protection objective for a revised standard, the Administrator finds appropriate and useful the estimates of tree seedling growth impacts (in terms of RBL) associated with a range of W126-based index values developed from the robust E–R functions for 11 tree species, that were described in the PA and proposal and are summarized in Table 4 above. In making judgments based on those observations, however, the Administrator has considered the broader evidence base and public welfare implications, including associated strengths, limitations and uncertainties. Thus, in drawing on estimates from this table, she is not making judgments simply about a specific magnitude of growth effect in seedlings that would be acceptable or unacceptable in the natural environment. Rather, the Administrator is using the estimates in the table, as suggested by CASAC and emphasized by some commenters, as a surrogate or proxy for consideration of the broader array of vegetation-related effects of potential public welfare significance, that include effects on growth of individual sensitive species and extend to ecosystem-level effects, such as community composition in natural forests, particularly in protected public lands, as well as forest productivity. In so doing, she notes that CASAC similarly viewed biomass loss as ''a scientifically valid surrogate of a variety of adverse effects to public welfare'' (Frey, 2014c, p. 10). Thus, in considering the appropriate level of public welfare protection for the revised standard, the Administrator gives primary attention to the relationship between W126 exposures and estimates of RBL in tree seedlings in Table 4, finding this to be a useful quantitative tool to inform her judgments in this matter.

In considering the RBL estimates in Table 4 above (drawn from the final PA), the Administrator takes note of comments from CASAC that also give weight to these relationships in formulating its advice and notes the CASAC comments on specific RBL values (Frey, 2014c). In so doing, she considers and contrasts comments and their context on RBL estimates of 2% and 6% for the median studied species.

With regard to the CASAC advice regarding 2% RBL for the median studied tree species, the Administrator notes, as an initial matter, the unclear basis for such a focus, as described in section IV.C.2 above and in the proposal. Further, she notes that the CASAC advice related to this RBL value was that it would be appropriate for the range of levels identified in the PA for the Administrator's consideration to ''include[] levels that aim for not greater than 2% RBL for the median tree species'' (Frey, 2014c, p. 14). As described in the proposal, the range identified in the PA, which the Administrator considered, extended down to W126 index levels for which the estimated RBL in the median tree species is less than or equal to 2%, consistent with the CASAC advice. In addition, the Administrator notes that only the lowest portion of this range (7–8 ppm-hrs) corresponds to an estimated RBL for the median tree species of less than or equal to 2%, with the remainder of CASAC's range (up to 15 ppm-hrs) associated with higher median RBL estimates. Thus, the Administrator understands CASAC to have identified 2% RBL for the median tree species as a benchmark falling within, and at one end of, the range of levels of protection that the CASAC considers appropriate for the revised standard to provide. However, the fact that the CASAC range included levels for which the RBL estimates were appreciably greater than 2% indicates that CASAC did not judge it necessary that the revised standard be based on the 2% RBL benchmark. Accordingly, the Administrator proposed revisions to the secondary standard based on options related to higher RBL estimates and associated exposures. After also considering public comments, the Administrator continues to consider the uncertainty regarding the extent to which associated effects on vegetation at lower O_3 exposures would be adverse to public welfare to be too great to provide a foundation for public welfare protection objectives for a revised secondary standard.

With regard to the CASAC comments on a 6% RBL estimate, the Administrator takes particular note of their characterization of this level of effect in the median studied species as ''unacceptably high'' (Frey, 2014c, pp. iii, 13, 14). These comments were provided in the context of CASAC's considering the significance of effects associated with a range of alternatives for the secondary standard. Moreover, the range recommended by CASAC excluded W126 index values for which the median species was estimated to have a 6% RBL,[212] based on the information before CASAC at the time (Frey, 2014c, p. 12–13). Accordingly, the EPA interprets these comments regarding 6% RBL to be of a different nature than the CASAC advice regarding a 2% median RBL, both because these two comments are framed to address different questions and because CASAC treated them differently in its recommended range.

In the Administrator's consideration of the RBL estimates to inform judgments on O_3 exposures of concern to public welfare and the appropriate protection that the secondary standard should provide from such exposures, she has given particular consideration to the current evidence for the relationship of reduced growth of sensitive tree species with ecosystem effects (as described in the ISA), CASAC's view of 6% RBL for the median studied species as unacceptably high, and the role of the Administrator's judgments regarding public welfare impacts of effects in specially protected natural systems, such as Class I areas. With regard to a point of focus among the median RBL estimates extending below 6% for purposes of judging the appropriate public welfare protection objectives for a revised secondary standard, the Administrator is mindful of the CASAC advice to consider lower levels if using a 3-year average, rather than annual, W126 index value.

In considering the CASAC advice, the Administrator notes that her judgments on a 3-year average index focus on the level of confidence in conclusions that might be drawn with regard to single as compared to multiple year impacts, as described above. For example, the Administrator, while recognizing the strength of the evidence with regard to quantitative characterization of O_3 effects on growth of tree seedlings and crops, and in addition to noting the additional difficulties for assessing the welfare impacts of O_3 on crops, takes note of the uncertainty associated with

[212] As summarized in IV.C.2 above (and noted in section IV.E.3 of the proposal), revisions to this table in the final PA, made in consideration of other CASAC comments, have resulted in changes to the median species RBL estimates such that the median species RBL estimate for a W126 index value of 17 ppm-hrs in this table in the final PA (5.3%) is nearly identical to the median species estimate for 15 ppm-hrs (the value corresponding to the upper end of the CASAC-identified range) in the second draft PA (5.2%), the review of which was the context for CASAC's advice on this point (Frey, 2014c). The median RBL estimate ranges from 5.3% to 3.8% across the range of W126 exposures (17 ppm-hrs to 13 ppm-hrs) that the Administrator proposed to conclude would provide the appropriate public welfare protection for a revised secondary standard.

drawing conclusions with regard to the extent to which small percent reductions in annual growth contribute to adverse effects on public welfare and the role of annual variability in environmental factors that affect plant responses to O_3. Moreover, as explained above, the Administrator concludes that concerns related to the possibility of a single unusually damaging year, inclusive of those described by the CASAC, can be addressed through use of a 3-year average metric. Thus, similar to the CASAC's view that a lower level would be appropriate with a 3-year form, the Administrator considers it appropriate to focus on a standard that would generally limit cumulative exposures to those for which the median RBL estimate would be somewhat lower than 6%.

In focusing on cumulative exposures associated with a median RBL estimate somewhat below 6%, the Administrator considers the relationships in Table 4, noting that the median RBL estimate is 6% for a cumulative seasonal W126 exposure index of 19 ppm-hrs. Considering somewhat lower values, the median RBL estimate is 5.7% (which rounds to 6%) for a cumulative seasonal W126 exposure index of 18 ppm-hrs and the median RBL estimate is 5.3% (which rounds to 5%) for 17 ppm-hrs. In light of her decision that it is appropriate to use a 3-year cumulative exposure index for assessing vegetation effects (described above), the potential for single-season effects of concern, and CASAC comments on the appropriateness of a lower value for a 3-year average W126 index, the Administrator concludes it is appropriate to identify a standard that would restrict cumulative seasonal exposures to 17 ppm-hrs or lower, in terms of a 3-year W126 index, in nearly all instances. In reaching this conclusion, based on the current information to inform consideration of vegetation effects and their potential adversity to public welfare, she additionally judges that the RBL estimates associated with marginally higher exposures in isolated, rare instances are not indicative of effects that would be adverse to the public welfare, particularly in light of variability in the array of environmental factors that can influence O_3 effects in different systems and uncertainties associated with estimates of effects associated with this magnitude of cumulative exposure in the natural environment.

While giving primary consideration to growth effects using the surrogate of RBL estimates based on tree seedling effects, the Administrator also recognizes the longstanding and robust evidence of O_3 effects on crop yield. She takes note of CASAC concurrence with the PA description of such effects as of public welfare significance and agrees. As recognized in the proposal, the maintenance of adequate agricultural crop yields is extremely important to the public welfare. Accordingly, research on agricultural crop species remains important for further illumination of mechanisms of action and physiological processes. Given that the extensive management of such vegetation, which as CASAC noted may reduce yield variability, may also to some degree mitigate potential O_3-related effects, however, judgments about the extent to which O_3-related effects on crop yields are adverse from a public welfare perspective are particularly difficult to reach. Further, management practices for agricultural crops are highly variable and generally designed to achieve optimal yields, taking into consideration various environmental conditions. As a result of this extensive role of management in optimizing crop yield, the Administrator notes the potential for greater uncertainty with regard to estimating the impacts of O_3 exposure on agricultural crop production than that associated with O_3 impacts on vegetation in natural forests. For all of these reasons, the Administrator is not giving the same weight to CASAC's statement regarding crop yield loss as a surrogate for adverse effects on public welfare, or the magnitude that would represent an adverse impact to public welfare, as to the CASAC's comments on RBL as a surrogate for an array of growth-related effects. Similarly, given the considerations summarized above and in the proposal, the Administrator concludes that agricultural crops do not have the same need for additional protection from the NAAQS as forested ecosystems and finds protection of public welfare from crop yield impacts to be a less important consideration in this review for the reasons identified, including the extensive management of crop yields and the dynamics of agricultural markets. Thus, the Administrator is not giving a primary focus to crop yield loss in selecting a revised secondary standard. She notes, however, that a standard revised to increase protection for forested ecosystems would also be expected to provide some increased protection for agricultural crops.

The Administrator has additionally considered the evidence and analyses of visible foliar injury. In so doing, the Administrator notes the ISA conclusion that ''[e]xperimental evidence has clearly established a consistent association of visible injury with O_3 exposure, with greater exposure often resulting in greater and more prevalent injury'' (U.S. EPA, 2013, section 9.4.2, p. 9–41). The Administrator also recognizes the potential for this effect to affect the public welfare in the context of affecting values pertaining to natural forests, particularly those afforded special government protection, as discussed in section IV.A.3 above. However, she recognizes significant challenges in judging the specific extent and severity at which such effects should be considered adverse to public welfare, in light of the variability in the occurrence of visible foliar injury and the lack of clear quantitative relationships with other effects on vegetation, as well as the lack of established criteria or objectives that might inform consideration of potential public welfare impacts related to this vegetation effect.

Further, the Administrator takes note of the range of evidence on visible foliar injury and the various related analyses, including additional observations drawn from the WREA biosite dataset in response to comments, as summarized in section IV.C.2 above. In so doing, she does not agree with CASAC's comment that a level of W126 exposure below 10 ppm-hrs is required to reduce foliar injury, noting some lack of clarity in the WREA and PA presentations of the WREA cumulative proportion analysis findings and their meaning (described in section IV.C.2.b above). She notes that the additional observations summarized in section IV.C.2 above indicate declines in proportions of sites with any visible foliar injury and biosite index scores with reductions in cumulative W126 exposure across a range of values extending at the high end well above 20 ppm-hrs, down past and including 17 ppm-hrs. In considering this information, however, the Administrator takes note of the current lack of robust exposure-response functions that would allow prediction of visible foliar injury severity and incidence under varying air quality and environmental conditions, as recognized in section IV.A.1.b above. Thus, while the Administrator notes that the evidence is not conducive to use for identification of a specific quantitative public welfare protection objective, due to uncertainties and complexities described in sections IV.A.1.b and IV.A.3 above, she concludes that her judgments above, reached with a focus on RBL estimates, would also be expected to provide an additional

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desirable degree of protection against visible foliar injury in sensitive vegetation. Accordingly, she considers a conclusion on the appropriateness of selecting a standard that will generally limit cumulative exposures above 17 ppm-hrs to be additionally supported by evidence for visible foliar injury, while not based on specific consideration of this effect.

With the public welfare protection objectives identified above in mind, the Administrator turns to her consideration of form and level for the revised secondary standard. In considering whether the current form should be retained or revised in order to provide the appropriate degree of public welfare protection, the Administrator has considered the analyses of air quality data from the last 13 years that describe the cumulative exposures, in terms of a 3-year W126 index, occurring at monitoring sites across the U.S. when the air quality metric at that location, in terms of the current standard's form and averaging time, is at or below different alternative levels. The Administrator notes both the conclusions drawn from analyses of the strong, positive relationship between these metrics and the findings that indicate the amount of control provided by the fourth-high metric.

The Administrator has also considered advice from CASAC and public commenters that support revision of the form to the W126 exposure index. The Administrator concurs with the underlying premise that O_3 effects on vegetation are most directly assessed using a cumulative seasonal exposure index, specifically the W126 exposure index. The Administrator additionally recognizes, based on analyses of the last 13 years of monitoring data, and consideration of modeling analyses with associated limitations and uncertainties, that cumulative seasonal exposures appear to have a strong relationship with design values based on the current form and averaging time. She additionally notes the correlation of reductions in W126 index values with reductions in precursor emissions over the past decade that were targeted at meeting the current O_3 standards (with fourth-high form), which indicate the control of cumulative seasonal exposures that can be achieved with a standard of the current form and averaging time.

With regard to recommendations from the CASAC that the form for the revised secondary standard should be the biologically relevant exposure metric, and related comments from the public indicating that the secondary standard must have such a form, the Administrator disagrees. In so doing, she notes that CAA section 109 does not impose such a requirement on the form or averaging time for the NAAQS, as explained in IV.C.2 above. She further notes that the averaging time and form of primary standards are often not the same as the exposure metrics used in reviews of primary standards, in which specific information on quantitative relationships between different exposure metrics and health risk is more often available than it is in reviews of secondary NAAQS. As discussed in section IV.C.2 above, with examples, a primary standard with a particular averaging time and form may provide the requisite public health protection from health effects that are most appropriately assessed using an exposure metric of a different averaging time and form and indicator, and the same principle can apply when establishing or revising secondary standards. The Administrator recognizes that the exposure metric and the standard metric can be quite similar, as in the case of consideration of short-term health effects with the primary O_3 standard. She also notes, however, as illustrated by the examples described in section IV.C.2 above, that it is not uncommon for the EPA to retain or adopt elements of an existing standard that the Administrator judges in combination across all elements, including in some cases a revised level, to provide the requisite protection under the Act, even if those elements do not neatly correspond to the exposure metric. Accordingly, she concludes that the Act does not require that the secondary O_3 standard be revised to match the exposure metric identified as biologically relevant in this review, as long as the revised standard provides the degree of protection required under CAA section 109(b)(2).

Based on the considerations described here, including the use of an exposure metric that CASAC has agreed to be biologically relevant and appropriate, related considerations summarized in the proposal with regard to air quality analyses and common uses of exposure metrics in other NAAQS reviews, the Administrator finds that, in combination with a revised level, the current form and averaging time for a revised secondary standard can be expected to provide the desired level of public welfare protection. Accordingly, she next turns to the important consideration of a level that, in combination with the form and averaging time, will yield a standard that specifies the requisite air quality for protection of public welfare. In so doing, she has recognized the recommendation by CASAC for revision of the form and averaging time and provided the basis for her alternative view, as described above. Further, in the context of the Administrator's decision on objectives for public welfare protection of a revised secondary standard, and with consideration of the advice from CASAC on levels for a W126-based standard, the Administrator has also reached the conclusion, as described above, that in order to provide the appropriate degree of public welfare protection, the revised secondary standard should restrict cumulative seasonal exposures to 17 ppm-hrs or lower, in terms of a 3-year average W126 index, in nearly all instances. Thus, the Administrator finds it appropriate to revise the standard level to one that, in combination with the form and averaging time, will exert this desired degree of control for cumulative seasonal exposures.

In considering a revised standard level, the Administrator has, in light of public comments, revisited the information she considered in reaching her proposed decision on a level within the range of 65 to 70 ppb, and additional information or insights conveyed with public comments. The primary focus of the Administrator's considerations in reaching her proposed decision was the multi-faceted analysis of air quality data from 2001 through 2013 documented in the technical memo in the docket (Wells, 2014a), as well as the earlier analyses and related information described in the PA (as summarized in section IV.E.4 of the proposal). This analysis describes the occurrences of 3-year W126 index values of a magnitude from 17 ppm-hrs through 7 ppm-hrs at monitor locations where O_3 concentrations met different alternative standards with the current form and averaging time, and has been expanded in consideration of public comments to present in summary form the more extensive historical dataset accompanying this analysis (Wells, 2015b). Focusing first on the air quality analyses for the most recent period for which data are available (2011–2013) and with the protection objectives identified above in mind, the Administrator observes that across the sites meeting the current standard of 75 ppb, the analysis finds 25 sites distributed across different NOAA climatic regions with 3-year average W126 index values above 17 ppm-hrs, with the values at nearly half of the sites extending above 19 ppm-hrs, with some well above. In comparison, she observes that across sites meeting an alternative

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standard of 70 ppb, the analysis for the period from 2011–2013 finds no occurrences of W126 metric values above 17 ppm-hrs and less than a handful of occurrences that equal 17 ppm-hrs. The more than 500 monitors that would meet an alternative standard of 70 ppb during the 2011–2013 period are distributed across all nine NOAA climatic regions and 46 of the 50 states (Wells, 2015b and associated dataset in the docket).

The Administrator notes that some public commenters, who disagreed with her proposed decision on form and averaging time, emphasized past occurrences of cumulative W126 exposure values above the range identified in the proposal (of 13 to 17 ppm-hrs). For example, these commenters emphasize data from farther back across the full time period of the dataset analyzed in the technical memorandum (2001–2013), identifying a value of 19.1 ppm-hrs at a monitor for which the fourth-high metric is 70 ppb for the 3-year period of 2006–2008. The Administrator notes, as discussed in section IV.C.2 above, that this was one of fewer than a handful of isolated occurrences of sites for which the fourth-high was at or below 70 ppb and the W126 index value was above 17 ppm-hrs, all but one of which were below 19 ppm-hrs. The Administrator additionally recognizes her underlying objective of a revised secondary standard that would limit cumulative exposures in nearly all instances to those for which the median RBL
estimate would be somewhat lower than 6%. She observes that the single occurrence of 19 ppm-hrs identified by the commenter among the nearly 4000 3-year W126 index values from across the most recently available 11 3-year periods of data at monitors for which the fourth-high metric is at or below 70 ppb is reasonably regarded as an extremely rare and isolated occurrence (Wells, 2015b). As such, it is unclear whether it would recur, particularly as areas take further steps to reduce O_3 to meet revised primary and secondary standards. Further, based on the currently available information, the Administrator does not judge RBL estimates associated with marginally higher exposures in isolated, rare instances to be indicative of adverse effects to the public welfare. Thus, the Administrator concludes that a standard with a level of 70 ppb and the current form and averaging time may be expected to limit cumulative exposures, in terms of a 3-year average W126 exposure index, to values at or below 17 ppm-hrs, in nearly all instances, and accordingly, to eliminate or virtually eliminate cumulative exposures associated with a median RBL of 6% or greater.

The Administrator recognizes that any standard intended to exert a very high degree of control on cumulative seasonal exposures, with the objective of limiting exposures above 17 ppm-hrs across the U.S., in nearly all instances, will, due to regional variation in meteorology and sources of O_3 precursors, result in cumulative seasonal exposures well below 17 ppm-hrs in many areas. Even implementation of a standard set in terms of the cumulative seasonal exposure metric, while limiting the highest exposures, would, due to regional variation in meteorology and sources of O_3 precursors, result in many areas with much lower exposures. Such variation in exposures occurring under a specific standard is not unexpected and the overall distribution of exposures estimated to occur with air quality conditions associated with different alternative standards is a routine part of the consideration of public health protection in reviews of primary standards, and can also play a role in the review of secondary standards. For these reasons, and in light of the discussion in section IV.C.2.d above on consideration of ''necessary'' protection, the Administrator notes that an expectation of differing exposures is not, in itself, a basis for concluding that the air quality would be more (or less) than necessary (and thus not requisite) for the desired level of public welfare protection.

The Administrator has also considered the protection afforded by a revised standard against other effects studied in this review, such as visible foliar injury and reduced yield for agricultural crops, and also including those associated with climate change. While noting the evidence supporting a relationship of O_3 in ambient air with climate forcing effects, as concluded in the ISA, the Administrator judges the quantitative uncertainties to be too great to support identification of a standard specific to such effects such that she concludes it is more important to focus, as she has done above, on setting a standard based on providing protection against vegetation-related effects which would be expected to also have positive implications for climate change protection through the protection of ecosystem carbon storage.

The Administrator additionally considers the extent of control for cumulative seasonal exposures exerted by a revised standard level of 65 ppb, the lower end of the proposed range. In focusing on the air quality analyses for the most recent 3-year period for which data are available, the Administrator observes that across the sites meeting a fourth-high metric of 65 ppb, the analysis finds no occurrences of W126 metric values above 11 ppm-hrs and 35 occurrences of a value between 7 ppm-hrs and 11 ppm-hrs, scattered across NOAA climatic regions. The Administrator finds these magnitudes of cumulative seasonal exposures to extend appreciably below the objectives she identified above for affording public welfare protection. In considering this alternative level, she additionally notes that data for only 276 monitors (less than 25 percent of the total with valid fourth-high and W126 metric values) were at or below a fourth-high value of 65 ppb during the period from 2011–2013. In so noting, she recognizes the appreciably smaller and less geographically extensive dataset available and the associated uncertainty for conclusions based on such an analysis.

Thus, based on the support provided by currently available information on air quality, the evidence base of O_3 effects on vegetation and her public welfare policy judgments, and after carefully taking the above comments and considerations into account, fully considering the scientific views of the CASAC, and also taking note of CASAC's policy views, the Administrator has decided to retain the current indicator, form and averaging time and to revise the secondary standard level to 70 ppb. In the Administrator's judgment, based on the currently available evidence and quantitative exposure and air quality information, a standard set at this level, in combination with the currently specified form, averaging time and indicator would be requisite to protect the public welfare from known or anticipated adverse effects. A standard set at this level provides an appreciable increase in protection compared to the current standard. The Administrator judges that such a standard would protect natural forests in Class I and other similarly protected areas against an array of adverse vegetation effects, most notably including those related to effects on growth and productivity in sensitive tree species. The Administrator believes that a standard set at 70 ppb would be sufficient to protect public welfare from known or anticipated adverse effects and believes that a lower standard would be more than what is necessary to provide such protection. This judgment by the Administrator appropriately recognizes

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that the CAA does not require that standards be set at a zero-risk level, but rather at a level that reduces risk sufficiently so as to protect the public welfare from known or anticipated adverse effects. Accordingly, the Administrator concludes that it is appropriate to revise the level for the secondary standard to 70 ppb (0.070 ppm), in combination with retaining the current form, indicator, and averaging time, in order to specify the level of air quality that provides the requisite protection to the public welfare from any known or anticipated adverse effects associated with the presence of O_3 in the ambient air.

D. Decision on the Secondary Standard

For the reasons discussed above, and taking into account information and assessments presented in the ISA and PA, the advice and recommendations of CASAC, and the public comments, as well as public welfare judgments, the Administrator is revising the level of the current secondary standard. Specifically, the Administrator has decided to revise the level of the secondary standard to a level of 0.070 ppm, in conjunction with retaining the current indicator, averaging time and form. Accordingly the revised secondary standard is 0.070 ppm O_3, as the annual fourth-highest daily maximum 8-hour average concentration, averaged over three years.

V. Appendix U: Interpretation of the Primary and Secondary NAAQS for O_3

A. Background

The EPA is finalizing the proposed Appendix U to 40 CFR part 50: Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone. The proposed Appendix U addressed the selection of ambient O_3 monitoring data to be used in making comparisons with the NAAQS, data reporting and data handling conventions for comparing ambient O_3 monitoring data with the level of the NAAQS, and data completeness requirements. The EPA solicited public comment on four elements where the proposed Appendix U differed from Appendix P to 40 CFR part 50, which addressed data handling conventions for the previous O_3 NAAQS. These included the following: (1) the addition of a procedure to combine data collected from two or more O_3 monitors operating simultaneously at the same physical location, (2) the addition of a provision allowing the Regional Administrator to approve ''site combinations'', or the combination of data from two nearby monitoring sites for the purpose of calculating a valid design value, (3) a change from the use of one-half of the method detection limit ($^1/_2$ MDL) to zero (0.000 ppm) as the substitution value in 8-hour average data substitution tests, and 4) a new procedure for calculating daily maximum 8-hour average O_3 concentrations for the revised NAAQS.

The EPA is also finalizing, as proposed, exceptional events scheduling provisions in 40 CFR 50.14 that will apply to the submission of information supporting claimed exceptional events affecting pollutant data that are intended to be used in the initial area designations for any new or revised NAAQS. The new scheduling provisions will apply to initial area designations for the 2015 O_3 NAAQS.

B. Data Selection Requirements

The EPA proposed this section in Appendix U to clarify which data are to be used in comparisons with the revised O_3 NAAQS. The EPA is finalizing this section in Appendix U as proposed.

First, the EPA proposed to combine data at monitoring sites with two or more O_3 monitoring instruments operating simultaneously into a single site-level data record for determining compliance with the NAAQS, and proposed an analytical approach to perform this combination (79 FR 75351–75352, December 17, 2014). Several commenters supported the EPA's proposed approach, including the State of Iowa, where 15 of the 20 monitoring sites currently operating two O_3 monitors simultaneously are located. Commenters supporting the proposal noted that a similar approach is already being used for lead and particulate monitoring, and that the proposed approach will help states meet data completeness requirements.

A few commenters supported the EPA's proposed approach with the additional restrictions that the monitoring instruments must use identical methods and be operated by the same monitoring agency. The EPA notes that at the time of this rulemaking, all monitors reporting O_3 concentration data to the EPA for regulatory use were FEMs. All current O_3 FEMs use an ultraviolet photometry sampling methodology and have been found to meet the performance criteria in 40 CFR part 53. Therefore, the EPA has no reason to believe that O_3 concentration data should not be combined across monitoring methods at the site level. Regarding the commenters' suggestion that data should not be combined when two or more monitors at the same site are operated by different monitoring agencies, the EPA is aware of only one instance where this presently occurs. In this instance, the monitors have been assigned distinct site ID numbers in the AQS database, so that data will not be combined across these monitors. Should future instances arise where two or more monitoring agencies decide to operate O_3 monitors at the same site, the EPA encourages these agencies to work together to establish a plan for how the data collected from these monitors should be used in regulatory decision making.

One state objected to combining data across monitors because the secondary monitors at their sites were used only for quality assurance purposes and data from these monitors should not be combined with data reported from the primary monitors. The EPA notes that concentration data collected to meet quality assurance requirements (*i.e.* precision and bias data) are reported and stored in a separate location within the AQS database and are not used for determining compliance with the NAAQS. The required quality assurance data are derived from O_3 standards and not from a separate O_3 monitor. However, if a separate O_3 monitor is used strictly for quality assurance purposes and does not meet the applicable monitoring requirements, it can be distinguished in AQS in such a manner that data from the secondary monitor would not be combined with data from the primary monitor.

Another commenter objected to the proposal because it would reduce the total number of comparisons made with the NAAQS. While this is true, the number of physical locations being compared with the NAAQS will not decrease under the proposed approach, and in fact may increase due to additional sites meeting the data completeness requirements.

Finally, two commenters submitted similar comments citing the EPA's evaluation of collocated O_3 monitoring data and precision data in the ISA (U.S. EPA, 2013, section 3.5.2), and stated that although the median differences in concentrations reported by the pairs of monitoring instruments were near zero, the extreme values were close to +/¥ 3.5%. The commenter argued that since the O_3 NAAQS are based on the fourth-highest annual value, data should not be combined across monitors because of the imprecision in the extreme values. The EPA disagrees, noting that the data presented in the ISA are based on hourly concentrations, while design values for the O_3 NAAQS are based on a 3-year average of 8-hour average concentrations. Thus, the random variability in the hourly O_3 concentration data due to monitoring imprecision will be reduced when concentrations are averaged for comparison with the NAAQS. Additionally, the precision data are typically collected at concentrations at or above the level of the NAAQS, thus the EPA expects that the level of precision documented in the ISA analysis is consistent with the level of precision in the fourth-highest daily maximum concentrations used for determining compliance with the NAAQS.

The EPA is finalizing this addition in Appendix U as proposed. In addition, the AQS database will be updated to require state agencies to designate a primary monitor at O_3 monitoring sites that report data under more than one Pollutant Occurrence Code (POC), a numeric indicator in AQS used to identify individual monitoring instruments. O_3 design value calculations in AQS will be updated so that the data will automatically be combined across POCs at a site, and a single design value will be reported for each site. The EPA notes that the substitution approach described above will only be applied to design value calculations for the revised O_3 standards, and that design values for previous O_3 standards will continue to be calculated at the monitor level, in accordance with the applicable appendices of 40 CFR part 50.

Second, the EPA proposed to add a provision in Appendix U that would allow the Regional Administrator to approve ''site combinations'', or to combine data across two nearby monitors for the purpose of calculating a valid design value. Although data handling appendices for previous O_3 standards do not explicitly mention site combinations, the EPA has approved over 100 site combinations since the promulgation of the first 8-hour O_3 NAAQS in 1997. Thus, the EPA's intention in proposing this addition was merely to codify an existing convention, and to improve transparency by implementing site combinations in AQS design value calculations.

Public commenters unanimously supported this proposed addition. Two commenters suggested that the EPA should require monitoring agencies to provide technical documentation supporting the similarities between sites approved for combining data, including a requirement for simultaneous monitoring whenever possible. One state requested that the EPA provide more detailed acceptability criteria for approving site combinations, while another state urged the EPA not to create a regulatory burden by prescribing detailed requirements codified in regulations.

The EPA is finalizing this addition as proposed in Appendix U. The EPA believes that approval of site combinations should be handled on a case-by-case basis, and that any requests for supporting documentation should be left to the discretion of the Regional Administrator. The EPA may issue future guidance providing general criteria for determining an acceptable level of similarity in air quality concentrations between monitored locations, but is not prescribing detailed criteria for approval of site combinations in this rulemaking.

Additionally, the AQS database will be updated with new fields for monitoring agencies to request site combinations, and an additional field indicating Regional Administrator approval. All pre-existing site combinations will be initially entered into the database as having already been approved by the Regional Administrator. Since this provision has already been used in practice under previous O_3 standards, site combinations will be applied to AQS design value calculations for both the revised O_3 standards and previous O_3 standards.

C. Data Reporting and Data Handling Requirements

First, the EPA proposed a change in Appendix U to the pre-existing 8-hour average data substitution test (40 CFR part 50, Appendix P, section 2.1) which is used to determine if a site would have had a valid 8-hour average greater than the NAAQS when fewer than 6 hourly O_3 concentration values are available for a given 8-hour period. The EPA proposed to change the value substituted for the missing hourly concentrations from one-half of the method detection limit of the O_3 monitoring instrument ($^1/_2$ MDL) to zero (0.000 ppm).

Several commenters supported the proposed change, stating that the use of a constant substitution value instead of $^1/_2$ MDL, which can vary across O_3 monitoring methods, would simplify design value calculations. One commenter noted that with a substitution value of zero, the data substitution test for an 8-hour average value greater than the NAAQS is equivalent to a sum of hourly O_3 concentrations greater than 0.567 ppm (*i.e.,* if the sum is 0.568 ppm or higher, the resulting 8-hour average must be at least 0.071 ppm, which is greater than the revised O_3 NAAQS of 0.070 ppm). Finally, one commenter opposed the proposed change in favor of some type of mathematical or statistical interpolation approach, but did not provide a specific recommendation.

The EPA is finalizing the proposed change in Appendix U, with the addition of a short clause making note of the equivalent summation approach described above. The purpose of the data substitution test is to identify 8-hour periods that do not meet the requirements for a valid 8-hour average, yet the reported hourly concentration values are so high that the NAAQS would have been exceeded regardless of the magnitude of the missing concentration values. The EPA believes that zero, being the lowest measured O_3 concentration physically possible, is the most appropriate value to substitute in this situation. Additionally, the EPA does not support the use of interpolation or other means of filling in missing monitoring data for O_3 NAAQS comparisons. Such an approach would be contrary to the EPA's long-standing policy of using only quality-assured and certified ambient air quality measurement data to determine compliance with the O_3 NAAQS.

Second, the EPA proposed a new procedure in Appendix U for determining daily maximum 8-hour O_3 concentrations for the revised NAAQS.[213] The EPA proposed to determine the daily maximum 8-hour O_3 concentration based on 17 consecutive moving 8-hour periods in each day, beginning with the 8-hour period from 7:00 a.m. to 3:00 p.m., and ending with the 8-hour period from 11:00 p.m. to 7:00 a.m. In addition, the EPA proposed that a daily maximum value would be considered valid if 8-hour averages were available for at least 13 of the 17 consecutive moving 8-hour periods, or if the daily maximum value was greater than the level of the NAAQS. This procedure is designed to eliminate ''double counting'' exceedances of the NAAQS based on overlapping 8-hour periods from two consecutive days with up to 7 hours in common, which was allowed under previous 8-hour O_3 NAAQS. A dozen public commenters expressed support for the proposed procedure, including several states.

One regional air quality management organization and three of its member states submitted similar comments stating that they agreed with the principle of eliminating ''double counting'' exceedances of the NAAQS

[213] This procedure will be adopted only for the revised O_3 NAAQS. Design values for the 1997 8-hour O_3 NAAQS and the 2008 8-hour O_3 NAAQS will continue to be calculated according to Appendix I and Appendix P of 40 CFR part 50, respectively.

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based on overlapping 8-hour periods, but suggested an alternative calculation procedure that would accomplish the same objective. The alternative procedure iteratively finds the highest 8-hour period in a given year, then removes this 8-hour period and all other 8-hour periods associated with that day, including any overlapping 8-hour periods on adjacent days, from the data until a daily maximum value is determined for each day of the year with sufficient monitoring data. The EPA examined a similar iterative procedure in a previous data analysis supporting the proposal (Wells, 2014b, Method 1). The EPA compared this procedure to the procedure proposed by the commenters using the data from the original analysis and found the resulting daily maximum 8-hour values to be nearly identical (Wells, 2015a). Additionally, the commenters' procedure suffers from the same limitations the EPA identified previously in the original analysis: added complexity in design value calculations, longer computational time, and challenges to real-time O_3 data reporting systems, which would have to re-calculate daily maximum 8-hour values for the entire year each time the system was updated with new data.

Three states submitted comments stating that they agreed with the proposed calculation procedure, but disagreed with the proposed requirements for determining a valid daily maximum 8-hour O_3 concentration. These states were primarily concerned that the proposed requirements would only allow a monitoring site to have four missing 8-hour averages during a day before the entire day would be invalidated, compared with six missing 8-hour averages allowed previously. Two of these states also stated concerns that the proposed requirements would be more difficult to meet while maintaining compliance with existing monitoring requirements such as biweekly quality assurance checks. The EPA compared annual data completeness rates calculated using the Appendix U requirements to annual data completeness rates calculated using the requirements under the previous O_3 standards across all U.S. monitoring sites based on data from 2004–2013 (Wells, 2015a). The national mean annual data completeness rate was 0.1% higher under the proposed Appendix U requirements than under the previous O_3 standards, and the national median annual data completeness rates were identical. In addition, the EPA notes that the Appendix U requirements allow for biweekly quality assurance checks and other routine maintenance to be performed between 5:00 a.m. and 9:00 a.m. local time without affecting data completeness. Thus, the EPA does not believe that the proposed daily data completeness requirements in Appendix U will be more difficult for monitoring agencies to meet.

Finally, two public commenters opposed the proposed procedures for determining daily maximum 8-hour concentrations. These commenters expressed similar concerns, primarily that not considering 8-hour periods starting midnight to 6:00 a.m. is less protective of public health than the procedure used to determine daily maximum 8-hour concentrations for the previous O_3 standards. The EPA believes that this approach provides the appropriate degree of protection for public health, noting that the hourly concentrations from midnight to 7:00 a.m. are covered under the 8-hour period from 11:00 p.m. to 7:00 a.m., which is included in the design value calculations proposed in Appendix U. At the same time, the proposed approach ensures that individual hourly concentrations may not contribute to multiple exceedances of the NAAQS, which the EPA believes is inappropriate given that people are only exposed once.

The EPA is finalizing as proposed in Appendix U the procedure for determining daily maximum 8-hour concentrations. The EPA does not believe that daily maximum 8-hour concentrations for two consecutive days should be based on overlapping 8-hour periods, since the exposures experienced by individuals only occur once. The EPA believes that the new procedure will avoid this outcome while continuing to make use of all hourly concentrations in determining attainment of the standards, without introducing unnecessary complexity into design value calculations, and without creating additional difficulties for monitoring agencies to meet the data completeness requirements.

D. Exceptional Events Information Submission Schedule

The ''Treatment of Data Influenced by Exceptional Events; Final Rule'' (72 FR 13560, March 22, 2007), known as the Exceptional Events Rule and codified at 40 CFR 50.14, contains generic deadlines for an air agency to submit to the EPA specified information about exceptional events and associated air pollutant concentration data. As discussed in this section and in more detail in the O_3 NAAQS proposal, without revisions to 40 CFR 50.14, an air agency may not be able to flag and submit documentation for some relevant data either because the generic deadlines may have already passed by the time a new or revised NAAQS is promulgated or because the generic deadlines require submission of documentation at least 12 months prior to the date by which the EPA must make a regulatory decision, which may be before air agencies have collected some of the potentially affected data. Specific to the revised O_3 NAAQS, revisions to 40 CFR 50.14 are needed because it is not possible for air agencies to flag and submit documentation for any exceptional events that occur in October through December of 2016 by 1 year before the designations are made in October 2017, as is required by the existing generic schedule.

The EPA is finalizing exceptional events scheduling provisions in 40 CFR 50.14, as proposed and as supported by multiple commenters, that will apply to the submission of information supporting claimed exceptional events affecting pollutant data that are intended to be used in the initial area designations for any new or revised NAAQS. The new scheduling provisions will apply to initial area designations for the revised O_3 NAAQS. The provisions that we are promulgating use a ''delta schedule'' that calculates the timelines associated with flagging data potentially influenced by exceptional events, submitting initial event descriptions and submitting exceptional events demonstrations based on the promulgation date of a new or revised NAAQS. The general data flagging deadlines in the Exceptional Events Rule at 40 CFR 50.14(c)(2)(iii) and the general schedule for submission of demonstrations at 40 CFR 50.14(c)(3)(i) continue to apply to data used in regulatory decisions other than those related to the initial area designations process under a new or revised NAAQS.[214]

The EPA acknowledges the concern raised by several commenters that a strengthened O_3 NAAQS may result in numerous demonstrations for exceptional events occurring between 2014 and 2016, the data years that the EPA will presumably use for initial area designation decisions made in October 2017.[215] Commenters noted that the proposed schedule is particularly burdensome for agencies needing to submit exceptional events packages for

[214] The EPA intends to consider changes to these retained scheduling requirements as part of the planned notice and comment rulemaking revisions to the 2007 Exceptional Events Rule.

[215] Governors may also use 2013 data to formulate their recommendations regarding designations.

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the third year to be used in a 3-year design value (*i.e.,* 2016 data). Several commenters recommended that the EPA either establish no defined schedule for data flagging and exceptional events demonstration submittal or allow a minimum of 2 years from the setting of any new or revised NAAQS for air agencies to provide a complete exceptional events demonstration. Given the CAA requirement that the EPA follow a 2-year designations schedule, the EPA cannot remove submittal schedules entirely for data influenced by exceptional events or provide a minimum 2-year period from the setting of a new or revised NAAQS for documentation submittal. Neither of these options would ensure that the EPA has time to consider event-influenced data in initial area designation decisions. Rather, the EPA is promulgating in this action an exceptional events schedule that provides air agencies with the maximum amount of time available to prepare exceptional events demonstrations and will still allow the EPA sufficient time to consider such exceptional events demonstrations in the designations process in advance of the date by which the EPA must send 120-day notification letters to states.[216] The EPA recognizes that the schedule promulgated in this action is compressed, particularly for the third year of data to be used in a 3-year design value, and we will work cooperatively with air agencies to accommodate this scenario.

Under the schedule promulgated in this action and assuming initial area designation decisions in October 2017 for the revised O_3 NAAQS, affected air agencies would need to flag data, submit initial event descriptions and submit demonstrations for exceptional events occurring in 2016 by May 31, 2017. This schedule provides approximately 5 months between the EPA's receipt of the demonstration package and the expected date of designation decisions and approximately 1 month between the EPA's receipt of a package and the date by which the EPA must notify states and tribes of intended modifications to the Governors' recommendations for designations (*i.e.,* 120-day letters).

While, for the third year of data anticipated to be used in a 3-year design value for the revised O_3 NAAQS, the promulgated schedule provides for demonstration submission 5 months after the end of the calendar year, the EPA expects that most submitting agencies will have additional time to prepare documentation as we expect the majority of potential O_3-related exceptional events to occur during the warmer months (*e.g.,* March through October). Additionally, the EPA will soon propose rule revisions to the 2007 Exceptional Events Rule and will release through a **Federal Register** Notice of Availability a draft guidance document to address Exceptional Events Rule criteria for wildfires that could affect O_3 concentrations. We expect to promulgate Exceptional Events Rule revisions and finalize the new guidance document before the October 2016 date by which states, and any tribes that wish to do so, are required to submit their initial designation recommendations for the revised O_3 NAAQS. Considered together, the EPA believes the exceptional events scheduling dates promulgated in this action, the upcoming Exceptional Events Rule revisions, the forthcoming guidance, and the existing guidance and examples of submitted demonstrations currently on the EPA's exceptional events Web site at *http://www2.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events*, will help air agencies submit information in a timely manner.

Applying the ''delta schedule'' promulgated in this action for air quality data collected in 2013 through 2014 that could be influenced by exceptional events and be considered during the initial area designations process for the revised O_3 NAAQS, results in extending to July 1, 2016, the otherwise applicable generic deadlines of July 1, 2014, and July 1, 2015, respectively, for flagging data and providing an initial description of an event (40 CFR 50.14(c)(2)(iii)). The schedule promulgated in this action also results in a July 1, 2016, date for flagging data and providing an initial description of an event for air quality data collected in 2015. The July 1, 2016, date for data collected in 2015 is the same as that which would apply under the existing generic deadline in the 2007 Exceptional Events Rule. Under the schedule promulgated in this action, October 1, 2016 is the deadline for submitting exceptional events demonstrations for data years 2013 through 2015. As noted previously, under the schedule promulgated in this action, affected air agencies would need to flag, submit initial event descriptions and submit demonstrations for exceptional events occurring in 2016 by May 31, 2017. The EPA believes these revisions will provide adequate time for air agencies to review potential O_3 exceptional events influencing compliance with the revised O_3 NAAQS, to notify the EPA by flagging the relevant data and providing an initial event description in AQS, and to submit documentation to support exceptional events demonstrations. The schedule revisions promulgated in this action will also allow the EPA to consider and act on the submitted information during the initial area designation process.

While the EPA will make every effort to designate areas for any new or revised NAAQS on a 2-year schedule, the EPA recognizes that under some circumstances we may need up to an additional year for the designations process to ensure that air agencies and the EPA base designations decisions on complete and sufficient information. The promulgated schedule accounts for the possibility that the EPA might announce after promulgating a new or revised NAAQS that we are extending the designations schedule beyond 2 years using authority provided in CAA section 107(d)(B)(i). If the EPA determines that we will follow a 3-year designation schedule, the deadline is 2 years and 7 months after promulgation of a new or revised NAAQS for states to flag data influenced by exceptional events, submit initial event descriptions and submit exceptional events demonstrations for the last year of data that will be used in the designations (*e.g.,* if the EPA were to designate areas in October 2018, the exceptional events submittal deadline for 2017 data would be May 31, 2018). If the EPA notifies states and tribes of a designations schedule between 2 and 3 years, the deadline for states to flag data affected by exceptional events, submit initial event descriptions, and submit exceptional events demonstrations associated with data from the last year to be considered would be 5 months prior to the date specified for designation decisions.

Therefore, using the authority provided in CAA section 319(b)(2) and in the 2007 Exceptional Events Rule at 40 CFR 50.14(c)(2)(vi), the EPA is modifying the schedule for flagging data and submitting exceptional events demonstrations considered for initial area designations by replacing the deadlines and information in Table 1 in 40 CFR 50.14 with the deadlines and information presented in Table 5. As we did in the O_3 NAAQS proposal, we are also providing Table 6 to illustrate how the promulgated schedule might apply to the designations process for the revised O_3 NAAQS and to designations

[216] See Section VIII.B for additional detail on the initial area designations process for the revised O_3 NAAQS.

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processes for other future new or revised NAAQS.[217]

Additionally, in conjunction with promulgating exceptional events schedules for initial area designations for new or revised NAAQS, the EPA, as proposed, is removing obsolete regulatory language in 40 CFR 50.14(c)(2)(iv) and (v) and 40 CFR 50.14(c)(3)(ii) and (iii) associated with exceptional events schedules for all historical standards.

TABLE 5—SCHEDULE FOR FLAGGING AND DOCUMENTATION SUBMISSION FOR DATA INFLUENCED BY EXCEPTIONAL EVENTS FOR USE IN INITIAL AREA DESIGNATIONS

Exceptional events/Regulatory action	Exceptional events deadline schedule [d]
Flagging and initial event description deadline for data years 1, 2 and 3 [a].	If state and tribal initial designation recommendations for a new/revised NAAQS are due August through January, then the flagging and initial event description deadline will be the July 1 prior to the recommendation deadline. If state and tribal recommendations for a new/revised NAAQS are due February through July, then the flagging and initial event description deadline will be the January 1 prior to the recommendation deadline.
Exceptional events demonstration submittal deadline for data years 1, 2 and 3 [a].	No later than the date that state and tribal recommendations are due to the EPA.
Flagging, initial event description and exceptional events demonstration submittal deadline for data year 4 [b] and, where applicable, data year 5 [c].	By the last day of the month that is 1 year and 7 months after promulgation of a new/revised NAAQS, unless either option a or b applies. a. If the EPA follows a 3-year designation schedule, the deadline is 2 years and 7 months after promulgation of a new/revised NAAQS. b. If the EPA notifies the state/tribe that it intends to complete the initial area designations process according to a schedule between 2 and 3 years, the deadline is 5 months prior to the date specified for final designations decisions in such EPA notification.

[a] Where data years 1, 2, and 3 are those years expected to be considered in state and tribal recommendations.

[b] Where data year 4 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under the standard designations schedule.

[c] Where data year 5 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under an extended designations schedule.

[d] The date by which air agencies must certify their ambient air quality monitoring data in AQS is annually on May 1 of the year following the year of data collection as specified in 40 CFR 58.15(a)(2). In some cases, however, air agencies may choose to certify a prior year's data in advance of May 1 of the following year, particularly if the EPA has indicated its intent to promulgate final designations in the first 8 months of the calendar year. Data flagging, initial event description and exceptional events demonstration deadlines for "early certified" data will follow the deadlines for "year 4" and "year 5" data.

[217] The range of dates identified in Table 6 is illustrative of the dates for the revised O_3 NAAQS. Users could increment these dates by any constant number (for example by 6 years for a hypothetical NAAQS promulgated in 2021) to develop a table with dates relevant to NAAQS promulgated in the future.

Table 6. Examples by Month of Applying the Promulgated Revised Schedule for Flagging and Documentation Submission for Data Influenced by Exceptional Events for Use in Initial Area Designations

		Month of NAAQS Promulgation, State and Tribal Recommendation, and Final Designations												
Exceptional Events / Regulatory Action	Exceptional Events Deadline Schedule[c]	Oct Oct 2015	Nov Nov 2015	Dec Dec 2015	Jan Jan 2016	Feb Feb 2016	Mar Mar 2016	Apr Apr 2016	May[d] May 2016	Jun[d] Jun 2016	Jul[d] Jul 2016	Aug[d] Aug 2016	Sep Sep 2016	Oct Oct 2016
Flagging and initial event description deadline for data years 1, 2, and 3.[a]	If state and tribal initial designation recommendations for a new/revised NAAQS are due August through January, then the flagging and initial event description deadline will be the July 1 prior to the recommendation deadline. If state and tribal recommendations for a new/revised NAAQS are due February through July, then the flagging and initial event description deadline will be the January 1 prior to the recommendation deadline.	July 1, 2016 (data years 2013, 2014, 2015)	July 1, 2016 (data years 2013, 2014, 2015)	July 1, 2016 (data years 2013, 2014, 2015)	July 1, 2016 (data years 2013, 2014, 2015)	Jan 1, 2017 (data years 2013, 2014, 2015)	Jan 1, 2017 (data years 2013, 2014, 2015)	Jan 1, 2017 (data years 2013, 2014, 2015)	Jan 1, 2017 (data years 2013, 2014, 2015)	Jan 1, 2017 (data years 2014, 2015, 2016)	Jan 1, 2017 (data years 2014, 2015, 2016)	July 1, 2017 (data years 2014, 2015, 2016)	July 1, 2017 (data years 2014, 2015, 2016)	July 1, 2017 (data years 2014, 2015, 2016)
Exceptional events demonstration submittal deadline for data years 1, 2, and 3.[a]	No later than the date that state and tribal recommendations are due to EPA.	by Oct 2016 (data years 2013, 2014, 2015)	by Nov 2016 (data years 2013, 2014, 2015)	by Dec 2016 (data years 2013, 2014, 2015)	by Jan 2017 (data years 2013, 2014, 2015)	by Feb 2017 (data years 2013, 2014, 2015)	by Mar 2017 (data years 2013, 2014, 2015)	by Apr 2017 (data years 2013, 2014, 2015)	by May 2017 (data years 2013, 2014, 2015)	by June 2017 (data years 2014, 2015, 2016)	by July 2017 (data years 2014, 2015, 2016)	by Aug 2017 (data years 2014, 2015, 2016)	by Sep 2017 (data years 2014, 2015, 2016)	by Oct 2017 (data years 2014, 2015, 2016)
AQS quality assurance and data certification	Annually on May 1 of the year following the year of data collection	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1	May 1
Flagging, initial event description and exceptional events demonstration submittal deadline for data year 4[b] and, where applicable, data year 5.[c]	By the last day of the month that is 1 year and 7 months after promulgation of a new/revised NAAQS, unless either option a or b applies. a. If the EPA follows a 3 year designation schedule, the deadline is 2 years and 7 months after promulgation of a new/revised NAAQS. b. If the EPA notifies the state/tribe that it intends to complete the initial area designations process according to a schedule between 2 and 3 years, the deadline is 5 months prior to the date specified for final designations decisions in such EPA notification.	by May 31, 2017 (data year 2016)	by June 30, 2017 (data year 2016)	by July 31, 2017 (data year 2016)	by Aug 31, 2017 (data year 2016 and potentially 2017)	by Sep 30, 2017 (data year 2016 and potentially 2017)	by Oct 31, 2017 (data year 2016 and potentially 2017)	by Nov 30, 2017 (data year 2016 and potentially 2017)	by Dec 31, 2017 (data year 2016 and potentially 2017)	by Jan 31, 2018 (data year 2017)	by Feb 28/29, 2018 (data year 2017)	by Mar 31, 2018 (data year 2017)	by Apr 30, 2018 (data year 2017)	by May 31, 2018 (data year 2017)
State & Tribal Recommendations to EPA		**Oct 2016**	**Nov 2016**	**Dec 2016**	**Jan 2017**	**Feb 2017**	**Mar 2017**	**Apr 2017**	**May 2017**	**June 2017**	**July 2017**	**Aug 2017**	**Sep 2017**	**Oct 2017**
EPA notifies States/Tribes of intended modifications to recommendations (EPA sends 120-day letters)		**June 2017**	**July 2017**	**Aug 2017**	**Sep 2017**	**Oct 2017**	**Nov 2017**	**Dec 2017**	**Jan 2018**	**Feb 2018**	**Mar 2018**	**Apr 2018**	**May 2018**	**June 2018**
Administrator Promulgates Final Designations		**Oct 2017**	**Nov 2017**	**Dec 2017**	**Jan 2018**	**Feb 2018**	**Mar 2018**	**Apr 2018**	**May 2018**	**June 2018**	**July 2018**	**Aug 2018**	**Sep 2018**	**Oct 2018**

[a] Where data years 1, 2, and 3 are those years expected to be considered in state and tribal recommendations.
[b] Where data year 4 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under the standard designations schedule.
[c] Where data year 5 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under an extended designations schedule.
[d] The date by which air agencies must certify their ambient air quality monitoring data in AQS is annually on May 1 of the year following the year of data collection as specified in 40 CFR 58.15(a)(2). In some cases, however, air agencies may choose to certify a prior year's data in advance of May 1 of the following year, particularly if the EPA has indicated its intent to promulgate final designations in the first 8 months of the calendar year. Data flagging, initial event description and exceptional events demonstration deadlines for "early certified" data will follow the deadlines for "year 4" and "year 5" data.

VI. Ambient Monitoring Related to O_3 Standards

A. Background

The EPA proposed to revise the state-by-state O_3 monitoring seasons; the PAMS monitoring requirements; the FRM for measuring O_3; and the FEM performance requirement specifications for automated O_3 analyzers. The EPA also proposed to make additional minor changes to the FEM analyzer performance testing requirements for NO_2 and particulate matter in part 53.

The EPA is finalizing changes to the length of the required O_3 monitoring season for 32 states and the District of Columbia. Section VI.B of this preamble provides an overview of the proposed changes to the length of the required O_3 monitoring seasons, a summary of significant public comments and our responses, and a summary of the final decisions made to the O_3 monitoring seasons for each state.

The EPA is finalizing changes to the PAMS monitoring requirements in 40 CFR part 58, Appendix D Section 5. Section VI.C of this preamble provides background on the PAMS program and current monitoring requirements, a summary of the proposed changes to the PAMS requirements, a summary of significant public comments and our responses, and a summary of the changes to the PAMS requirements in this final rule.

The EPA is finalizing changes to the FRM for O_3 in Section VI.D of this preamble and to the associated FEM performance requirement specifications for automated O_3 analyzers in Section VI.E. A summary of significant public comments and our responses are provided and a summary of the final changes to the FRM and FEM requirements in this final rule. The EPA is also finalizing minor additional changes to Part 53 including conforming changes to the FEM performance testing requirements in Table B–1 and Figure B–5 for NO_2; extending the period of time for the Administrator to take action on a request for modification of a FRM or FEM from 30 days to 90 days in part 53.14; and removing an obsolete provision for manufacturers to submit Product Manufacturing Checklists for fine and coarse particulate matter monitors in part 53.9.

B. Revisions to the Length of the Required O_3 Monitoring Seasons

Unlike the ambient monitoring requirements in 40 CFR part 58 for other criteria pollutants that mandate year-round monitoring at State and Local Air Monitoring Stations (SLAMS), O_3 monitoring is only required during the seasons of the year that are conducive to O_3 formation. These seasons vary in length from place-to-place as the conditions conducive to the formation of O_3 (*i.e.,* seasonally-dependent factors such as ambient temperature, strength of solar insolation, and length of day) differ by location. In some locations, conditions conducive to O_3 formation are limited to the summer months of the year. In other states with warmer climates (*e.g.,* California, Nevada, and Arizona), the currently required O_3 season is year-round. Elevated levels of winter-time O_3 have also been measured in some western states where precursor emissions can interact with sunlight off the snow cover under very shallow, stable boundary layer conditions (U.S. EPA 2013).

The EPA has determined that the proposed lengthening of the O_3 monitoring seasons in 32 states and the District of Columbia is appropriate. Ambient O_3 concentrations in these areas could approach or exceed the level of the NAAQS, more frequently and during more months of the year compared with the current season lengths. It is important to monitor for O_3 during the periods when ambient concentrations could approach the level of the NAAQS to ensure that the public is informed when exposure to O_3 could reach or has reached a level of concern.

The EPA completed an analysis to address whether extensions of currently required monitoring seasons are appropriate (Rice, 2014). In this analysis, we used all available data in AQS, including data from monitors that collected O_3 data year-round during 2010–2013. More than half of O_3 monitors are voluntarily operated on a year-round basis by monitoring agencies. We determined the number of days where one or more monitors had a daily maximum 8-hour O_3 average equal to or above 0.060 ppm in the months outside each state's current O_3 monitoring season and the pattern of those days in the out-of-season months. We believe that a threshold of 0.060 ppm, taking into consideration reasonable uncertainty, serves as an appropriate indicator of ambient conditions that may be conducive to the formation of O_3 concentrations that approach or exceed the NAAQS. We also considered regional consistency, particularly for those states with little available data. We note that seasonal O_3 patterns vary year-to-year due primarily to highly variable meteorological conditions conducive to the formation of elevated O_3 concentrations early or late in the season in some years and not others. The EPA believes it is important that O_3 monitors operate during all periods when there is a reasonable possibility of ambient levels approaching the level of the NAAQS.

Basing O_3 monitoring season requirements on the goal of ensuring monitoring when ambient O_3 levels approach or exceed the level of the NAAQS supports established monitoring network objectives described in Appendix D of Part 58, including the requirement to provide air pollution data to the general public in a timely manner [218] and to support comparisons of an area's air pollution levels to the NAAQS. The operation of O_3 monitors during periods of time when ambient levels approach or exceed the level of the NAAQS ensures that unusually sensitive people and sensitive groups are alerted to O_3 levels of potential health concern allowing them to take precautionary measures. The majority of O_3 monitors in the U.S. report to AIRNOW,[219] as well as to state-operated Web sites and automated phone reporting systems. These programs support many objectives including real-time air quality reporting to the public, O_3 forecasting, and the verification of real-time air quality forecast models.

1. Proposed Changes to the Length of the Required O_3 Monitoring Seasons

The EPA proposed to extend the length of the required O_3 monitoring season in 32 states and the District of Columbia. The proposed changes were an increase of one month for 22 states (Connecticut, Delaware, Idaho, Illinois, Iowa, Kansas, Maryland, Massachusetts, Minnesota, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas (northern portion only), Virginia, and West Virginia) and the District of Columbia, an increase of one and one half months for Wisconsin, an increase of two months for four states (Indiana, Michigan, Montana, and North Dakota), an increase of four months for Florida and South Dakota, an increase of five months for Colorado, and an increase of seven months for Utah. For Wyoming, we proposed to add three months at the beginning of the season and remove one month at the end of the season, resulting in a net increase of two months. Ozone season requirements are currently split by Air Quality Control Region (AQCR) in Louisiana and Texas. We proposed lengthening the required season in the northern part of Texas (AQCR 022, 210,

[218] Public reporting requirements are detailed in 40 CFR part 58 Appendix G, Uniform Air Quality Index (AQI) and Daily Reporting.

[219] See *http://airnow.gov/.*

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211, 212, 215, 217, and 218) by one month and leaving the year-round O_3 season in the southern part of Texas (AQCRs 106, 153, 213, 214, and 216) unchanged. No changes were proposed for the AQCRs in Louisiana. As noted earlier, in a few states with limited available data and few exceedance days outside the currently-required season (Iowa, Missouri, and West Virginia), the proposed changes were made by considering supporting information from the surrounding states. These changes involved the proposed addition of one month (March) to the currently-required O_3 seasons for these states.

The EPA also proposed that O_3 monitors at all National Core Multipollutant Monitoring Stations (NCore) be operated year-round, January through December, regardless of the length of the required O_3 season for the remainder of the SLAMS within each state.

We noted that the EPA Regional Administrators have previously approved deviations from the required O_3 monitoring seasons as allowed by paragraph 4.1(i) of 40 CFR part 58, Appendix D. We proposed to retain the rule language permitting such deviations from the required O_3 monitoring seasons, but note that finalized changes to O_3 monitoring season requirements would revoke all existing Regional Administrator-granted waiver approvals. As appropriate, monitoring agencies could seek new approvals for seasonal deviations. Any seasonal deviations based on the Regional Administrator's waiver of requirements must be described in the state's annual monitoring network plan and updated in the AQS.

Given the timing of the final rulemaking and any associated burden on state/local monitoring agencies to implement the extended O_3 seasons, we proposed that implementation of the revised O_3 seasons would become effective at SLAMS (including NCore sites) on January 1, 2017. We solicited comment on whether the revised seasons could be implemented beginning January 1, 2016, for all monitors or for a subset of monitors, such as those currently operating year-round or on a schedule that corresponds to the proposed O_3 season.

2. Comments on the Length of the Required O_3 Monitoring Seasons

We received several comments on the proposed revisions to O_3 monitoring seasons. Several commenters supported the proposed O_3 season length changes and agreed that O_3 monitoring seasons should reflect the times of year when O_3 may approach or exceed the level of the NAAQS. A few commenters noted the complexities that would arise in the implementation of multi-state planning agreements if states that shared an MSA had different required O_3 monitoring seasons. Two state agencies that supported season length changes also recommended changes to neighboring states' O_3 seasons. New York recommended that Connecticut's proposed O_3 season be further extended (adding the month of October) to match the proposed season in New York (March–October) because they share a major MSA and nonattainment area, and the highest design value monitor in the nonattainment area is often in Connecticut. The results from the EPA's analysis did not support the addition of October for Connecticut. The EPA recognizes that there may be value in having a consistent O_3 season across multi-state planning areas. We recommend that monitoring agency representatives from New York and Connecticut contact their respective EPA Regional Office to jointly develop a monitoring plan to provide coverage of the MSA for a longer period of time. Consistent with the results from the EPA's analysis and consistent with our proposal, the EPA is finalizing the March–October season in New York and the March–September season in Connecticut.

Although no changes were proposed for Arkansas, the Arkansas Department of Environmental Quality recommended that the O_3 season in the nonattainment area that includes Crittenden County, Arkansas (March–November) be consistent with the O_3 seasons in Tennessee (March–October) and Mississippi (March–October) by either shortening the O_3 season in Arkansas or lengthening the O_3 season by one month in Tennessee and Mississippi. Based on the results from the EPA's analysis and consistent with our proposal, the EPA is not finalizing any changes to the current O_3 seasons in Arkansas, Tennessee, or Mississippi. There is currently one monitor operating in Crittenden County. We recommend that Arkansas work with their EPA Regional Administrator to consider a waiver for the monitor(s) in Crittenden County to allow a deviation (shortened season) from the required O_3 season if the agency demonstrates that such a deviation is appropriate for consistency in the nonattainment area.

Two commenters noted the need to extend seasons to capture wintertime O_3 events. One commenter urged the EPA to extend monitoring to year-round in the intermountain west (specifically Wyoming) to adequately capture summer and winter O_3 problem days and noted especially two monitors in the Pinedale area of Wyoming that should be operated year-round. The EPA's analysis showed that there were no days that were $\geq$ 0.060 ppm in Wyoming for the months of October–December and that the Wyoming Department of Environmental Quality is currently operating about 70% of their O_3 monitors year-round including all O_3 monitors in Sublette County, which includes the Pinedale area. Another commenter supported lengthening the seasons for states in the western U.S. where wintertime O_3 could be an issue in light of the unique and growing O_3 pollution problems caused by oil and gas development activities. They also recommended that the EPA expand the O_3 monitoring season to year-round for North Dakota, South Dakota, and Montana beyond what was proposed. The number of observed days that were $\geq$ 0.060 ppm in the months outside the season proposed for these states (one day for North Dakota and no days observed for South Dakota and Montana) do not support a further extension to the length of the O_3 monitoring season beyond what was proposed. These states are already operating a large percentage of their monitors year-round (89% in North Dakota, 100% in South Dakota, and 78% in Montana). The EPA is finalizing the seasons as proposed in Wyoming (January–September), North Dakota (March–September), South Dakota (March–October), and Montana (April–September). The EPA encourages these states to continue year-round operation of their monitors to determine what areas are affected by elevated levels of winter-time O_3.

The commenters who opposed lengthening the O_3 monitoring seasons noted concerns with the threshold (0.060 ppm) used as the basis for the changes and the length of time (2010–2013) for which ambient data were retrieved and analyzed. Many of those with concerns recommended that levels in the proposed range (*e.g.,* 0.065 ppm or 0.070 ppm) or the current NAAQS level of 0.075 ppm be used as the appropriate threshold for determining the O_3 season. With regard to the 0.060 ppm threshold used, this value is consistent with the 85 percent threshold used to require additional O_3 monitoring based on Appendix D requirements, which include the MSA population and design value.[220] As noted previously, year-to-year variability occurs in seasonal O_3 patterns based on highly variable and unpredictable meteorological

[220] See 40 CFR part 58, appendix D, Table D–2.

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conditions, which can support the formation of early or late season elevated O_3 concentrations in some years and not in other years. This threshold serves as an appropriate indicator of ambient conditions that may be conducive to the formation of O_3 concentrations that approach or exceed the level of the NAAQS.

Certain logistical complexities were noted if longer seasons were required, including site access during winter and the challenge of getting the monitoring equipment ready in time. Four states noted concerns with operator safety and anticipated their inability to access sites due to early spring snowfall. The EPA agrees that site access could be an issue depending on weather conditions and notes that specific site monitoring season deviations may be appropriate. We suggest that this be addressed through the monitoring season waiver process with the EPA Regional Administrator. Any deviations based on the Regional Administrator's waiver of requirements must be described in the state's annual monitoring network plan and updated in AQS.

Several commenters had concerns about the additional cost and resources needed to expand the O_3 monitoring seasons. There was some disagreement with the EPA's total annual average cost estimate of $230,000 which took into account the number of O_3 monitors already operating year-round across the country. Commenters noted specifically that the proposed extension of required monitoring seasons would increase operational costs and potentially impact the resources available for other monitoring efforts. The added cost of operating O_3 monitors over a longer period was noted by some commenters, referencing both the cost of staff to operate the monitors, as well as the additional wear and tear those O_3 monitors would experience over a longer operational period. They noted that extending their required monitoring season by adding the month of March would increase staffing requirements for monitor operation and quality assurance. They also noted that the life expectancy of equipment would be reduced due to increased wear and tear. The EPA acknowledges that operational costs for O_3 monitoring networks will incrementally increase in states where required seasons have been lengthened. We encourage monitoring agencies to review available technology and operational procedures to institute practices that could potentially reduce such costs, such as the automation of quality control and calibration checks and remote access to evaluate monitor operations. As noted earlier, all states operated at least a portion of their O_3 monitoring network outside of the required O_3 season during the 2010–2013 data period and reported the data to AQS. In addition, many states are operating more than the minimum number of monitors required to support the basic monitoring objectives described in 40 CFR part 58, Appendix D. Some states have a large percentage of their total O_3 monitors operating outside the currently-required O_3 season and some states have a small percentage. In situations where states are already operating a large number of their O_3 monitors outside their current O_3 season, the actual cost increase will be less. In cases where states have a small number of monitors operating outside their current O_3 season, in addition to automation and remote access, those states could investigate with their Regional Administrator the process in 40 CFR part 58.14 for reducing the total number of operating monitors that are above the number required by 40 CFR, part 58, appendix D to offset the cost of extending the O_3 monitoring season in their state.

Two commenters had concerns about the 4-year period of time evaluated in the EPA's analysis and noted that the 4-year period of time evaluated does not take into account meteorological anomalies and other weather induced situations and is not consistent with the 3 years used to calculate design values. One state agency's comments referenced their own analysis showing concentrations going back 20 years. They noted that 2010 was an unusual year and inclusion of such an unusual year in the 4-year period (2010–2013) of the EPA's analysis provides too much weight on those data. As noted earlier, year-to-year variability occurs in seasonal O_3 patterns based on variable meteorological conditions and given the impracticality of forecasting such conditions that affect O_3 photochemistry, the EPA believes it is important that O_3 monitors operate when there is a reasonable possibility of ambient levels approaching the level of the NAAQS. Another state agency commented that 4 years appeared to be an unusual number of years given that design values are based on 3 years. To support the proposed rule in 2014, the EPA's analysis of O_3 seasons began in 2013. At that time the EPA's analysis considered the most recent 3 years of certified data (2010–2012) and updated the analysis to add a fourth year (2013) when the data were quality-assured, certified, and available in AQS. We used 4 years of data, including the most recent year (2013) to include an additional year of potentially-variable meteorological conditions to propose changes to the seasons. The EPA treated all years equally and did not put any more weight on the 2010 data than any of the other years used in the analysis. The EPA believes that using recently-available data across multiple years to capture varying meteorological conditions was appropriate to support the decisions on extending the O_3 seasons. One commenter disagreed with the EPA's definition of year-round (at least 20 daily observations in all 12 months of at least 1 year of the 4-year period). The definition of year-round was used to estimate the number of monitors being operated outside a state's required O_3 season and also used for the EPA's Information Collection Request (ICR). All available data in AQS were used for the O_3 season analysis, including data from year-round monitors.

Two commenters noted that ''regional consistency'' is not a scientific reason and is not needed for making changes to the O_3 seasons. One commenter noted that significant geographical, meteorological and demographic differences exist between neighboring states that may not warrant identical monitoring seasons. The EPA notes that regional consistency was considered, but only important for a few states where little data were available and the neighboring states had more available data and a sufficient number of days that were ≥ 0.060 ppm to support the proposed O_3 season changes. Regional consistency was not important for other states.

Some commenters expressed support for the proposed requirement that NCore O_3 sites operate year-round. They questioned whether data from NCore stations outside the O_3 season will be used for designations and requested that the EPA exclude those data from the designations process. Consistent with the designations process for all criteria pollutants, the states, tribes, and the EPA use all data available in AQS that meet the quality assurance requirements in 40 CFR part 58, Appendix A for the designations process. Given that O_3 data from NCore stations will meet these requirements, there is no rational basis for excluding these data from comparison to the NAAQS. Accordingly, such data from NCore stations cannot be excluded and will be treated in a manner equivalent to all other O_3 data in AQS. The EPA expects that the highest O_3 values will occur during the required O_3 season; therefore, we don't anticipate that NCore data from the out-of-season months will contribute to the design value used in

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the designations process. The EPA is finalizing the requirement for year-round O_3 monitoring at NCore stations.

The EPA Regional Administrators have previously approved deviations from the required O_3 monitoring seasons through rulemakings (64 FR 3028, January 20, 1999; 67 FR 57332, September 10, 2002; and 69 FR 52836, August 30, 2004). The current ambient monitoring rule, in paragraph 4.1(i) of 40 CFR part 58, Appendix D (71 FR 61319, October 17, 2006), allows the EPA Regional Administrators to approve changes to the O_3 monitoring season without rulemaking. The EPA is retaining the rule language allowing such deviations from the required O_3 monitoring seasons without rulemaking. In the finalized revision to paragraph 4.1(i) of 40 CFR part 58, Appendix D, the EPA is clarifying the minimum considerations that should be taken into account when reviewing requests, and clarifying that changes to the O_3 seasons finalized in this rule revoke all previously approved seasonal deviations. The EPA clarifies that all O_3 season waivers will be revoked when this final rule becomes effective. We encourage monitoring agencies with existing waivers to engage their EPA Regions as soon as possible to evaluate whether new or continued waivers are appropriate given the level of the revised O_3 NAAQS.

We received three comments for and three comments against early implementation of the revised O_3 seasons by the start of the applicable O_3 season in each state by January 1, 2016. Those commenters in favor of early implementation of the revised O_3 seasons are already operating a large percentage of O_3 monitors year-round or outside the current O_3 monitoring season in their state. Those commenters against early implementation cited concerns with the need for additional time to implement the revised O_3 seasons, especially in areas where access in order to service and support the monitoring equipment may be problematic during winter weather conditions, and the undue burden on already constrained state resources. One commenter noted that given the date for the final rule (October 1, 2015) that there is insufficient time for public review of their annual monitoring network plan due July 1, 2015, for early implementation in 2016. The EPA encourages those agencies who are able to implement the O_3 season changes early to do so by the start of the applicable O_3 season in their state in 2016. However, taking into consideration the timing and potential burden on monitoring agencies, the EPA is finalizing the requirement for implementing the revised O_3 seasons no later than the start of the applicable O_3 monitoring season in 2017, as proposed.

3. Final Decisions on the Length of the Required O_3 Monitoring Seasons

Final changes to the required O_3 monitoring seasons are summarized in this section as well as in revised Table D–3 in 40 CFR part 58, Appendix D.

Detailed state-by-state technical information has been placed in the docket to document the basis for the EPA's decision on each state. This information includes state-by-state maps and number of days that were ≥ 0.060 ppm; distribution charts of the number of days that were ≥ 0.060 ppm by month and state; and detailed information regarding AQS site IDs, dates and concentrations of all occurrences of the 8-hour daily maximum of at least 0.060 ppm between 2010 and 2013. Summaries have also been prepared for each state including the former and proposed O_3 monitoring seasons.

No changes to the required O_3 monitoring season were proposed or finalized for these states: Alabama, Alaska, Arizona, Arkansas, California, Georgia, Hawaii, Kentucky, Northern Louisiana (AQCR[221] 019, 022), Southern Louisiana (AQCR 106), Maine, Mississippi, Nevada, New Mexico, Oklahoma, Oregon, Tennessee, Southern Texas (AQCR 106, 153, 213, 214, 216), Vermont, Washington, Puerto Rico, Virgin Islands, Guam, and American Samoa. All existing O_3 season deviations or waivers are revoked.

Changes to the required O_3 monitoring seasons are finalized as follows for these states and the District of Columbia and all existing O_3 season deviations or waivers are revoked.

Colorado: Proposed addition of January, February, October, November, and December is finalized. The required season is revised to January–December.

Connecticut: Proposed addition of March is finalized, revising season to March–September.

Delaware: Proposed addition of March is finalized, revising season to March–October.

District of Columbia: Proposed addition of March is finalized, revising season to March–October.

Florida: Proposed addition of January, February, November, and December is finalized. The required season is revised to January–December.

Idaho: Proposed addition of April is finalized, revising season to April–September.

[221] Air Quality Control Region.

Illinois: Proposed addition of March is finalized, revising season to March–October.

Indiana: Proposed addition of March and October, revising season to March–October.

Iowa: Proposed addition of March is finalized, revising season to March–October.

Kansas: Proposed addition of March is finalized, revising season to March–October.

Maryland: Proposed addition of March is finalized, revising season to March–October.

Massachusetts: Proposed addition of March is finalized, revising season to March–September.

Michigan: Proposed addition of March and October is finalized, revising season to March–October.

Minnesota: Proposed addition of March is finalized, revising season to March–October.

Missouri: Proposed addition of March is finalized, revising season to March–October.

Montana: Proposed addition of April and May is finalized, revising season to April–September.

Nebraska: Proposed addition of March is finalized, revising season to March–October.

New Hampshire: Proposed addition of March is finalized, revising season to March–September.

New Jersey: Proposed addition of March is finalized, revising season to March–October.

New York: Proposed addition of March is finalized, revising season to March–October.

North Carolina: Proposed addition of March is finalized, revising season to March–October.

North Dakota: Proposed addition of March and April is finalized, revising season to March–September.

Ohio: Proposed addition of March is finalized, revising season to March–October.

Pennsylvania: Proposed addition of March is finalized, revising season to March–October.

Rhode Island: Proposed addition of March is finalized, revising season to March–September.

South Carolina: Proposed addition of March is finalized, revising season to March–October.

South Dakota: Proposed addition of March, April, May, and October is finalized, revising season to March–October.

Texas (Northern AQCR 022, 210, 211, 212, 215, 217, 218): Proposed addition of November is finalized, revising season to March–November.

Utah: Proposed addition of January, February, March, April, October, November, and December is finalized. The required season is revised to January–December.

Virginia: Proposed addition of March is finalized, revising season to March–October.

West Virginia: Proposed addition of March is finalized, revising season to March—October.

Wisconsin: Proposed addition of March and April 1—15 is finalized, revising season to March—October 15.

Wyoming: Proposed addition of January, February, March, and removal of October is finalized, revising season to January—September.

Finally, we are finalizing the required O_3 monitoring season for all NCore stations to be year-round (January—December) regardless of the required monitoring season for the individual state in which the NCore station is located.

C. Revisions to the PAMS Network Requirements

Section 182 (c)(1) of the CAA required the EPA to promulgate rules for enhanced monitoring of O_3, NO_X, and VOCs for nonattainment areas classified as serious (or above) to obtain more comprehensive and representative data on O_3 air pollution. In addition, Section 185B of the CAA required the EPA to work with the National Academy of Sciences (NAS) to conduct a study on the role of O_3 precursors in tropospheric O_3 formation and control. As a result of this study, the NAS issued the report entitled, ''Rethinking the Ozone Problem in Urban and Regional Air Pollution'', (NAS, 1991).

In response to the CAA requirements and the recommendations of the NAS report, on February 12, 1993 (58 FR 8452), the EPA revised the ambient air quality surveillance regulations to require PAMS in each O_3 nonattainment area classified as serious, severe, or extreme (''PAMS areas''). As noted in the EPA's Technical Assistance Document (TAD) for Sampling and Analysis of Ozone Precursors (U.S. EPA, 1998), the current objectives of the PAMS program are to: (1) Provide a speciated ambient air database that is both representative and useful in evaluating control strategies and understanding the mechanisms of pollutant transport by ascertaining ambient profiles and distinguishing among various individual volatile organic compounds (VOCs); (2) provide local, current meteorological and ambient data to serve as initial and boundary condition information for photochemical grid models; (3) provide a representative, speciated ambient air database that is characteristic of source emission impacts to be used in analyzing emissions inventory issues and corroborating progress toward attainment; (4) provide ambient data measurements that would allow later preparation of unadjusted and adjusted pollutant trends reports; (5) provide additional measurements of selected criteria pollutants for attainment/nonattainment decisions and to construct NAAQS maintenance plans; and (6) provide additional measurements of selected criteria and non-criteria pollutants to be used for evaluating population exposure to air toxics as well as criteria pollutants.

The original requirements called for two to five fixed sites per PAMS area depending on the area's population. Four types of PAMS sites were identified including upwind (Type 1), maximum precursor emission rate (Type 2), maximum O_3 concentration (Type 3), and extreme downwind (Type 4) sites. Each PAMS site was required to measure O_3, nitrogen oxide (NO), NO_2, speciated VOCs, selected carbonyl compounds, and selected meteorological parameters. In addition, upper air meteorological monitoring was required at one site in each PAMS area.

In the October 17, 2006 monitoring rule (71 FR 61236), the EPA revised the PAMS requirements to only require two sites per PAMS area. The intent of the revision was to ''allow PAMS monitoring to be more customized to local data needs rather than meeting so many specific requirements common to all subject O_3 nonattainment areas; the changes also gave states the flexibility to reduce the overall size of their PAMS programs—within limits—and to use the associated resources for other types of monitoring they consider more useful.'' In addition to reducing the number of required sites per PAMS area, the 2006 revisions also limited the requirement for carbonyl measurements (specifically formaldehyde, acetaldehyde, and acetone) to areas classified as serious or above for the 8-hour O_3 standards. This change was made in recognition of carbonyl sampling issues which were believed to cause significant uncertainty in the measured concentrations.

Twenty-two areas were classified as serious or above O_3 nonattainment at the time the PAMS requirements were promulgated in 1993. On July 18, 1997 (62 FR 38856), the EPA revised the averaging time of the O_3 NAAQS from a 1-hour averaging period to an 8-hour averaging period. On June 15, 2005 (70 FR 44470), the EPA revoked the 1-hour; however, PAMS requirements were identified as requirements that had to be retained in the anti-backsliding provisions included in that action. Therefore, PAMS requirements continue to be applicable to areas that were classified as serious or above nonattainment for the 1-hour O_3 standards as of June 15, 2004. Currently, 25 areas are subject to the PAMS requirements with a total of 75 sites. As will be discussed in detail later, the current PAMS sites are concentrated in the Northeast U.S. and California with relatively limited coverage in the rest of the country (Cavender, 2014).

The first PAMS sites began operation in 1994, and have been in operation for over 20 years. Since the start of the program, there have been many changes to the nature and scope of the O_3 problem in the U.S. as well as to our understanding of it. The O_3 standards has been revised multiple times since the PAMS program was first implemented. On July 18, 1997, the EPA revised the O_3 NAAQS to a level of 0.08 parts per million (ppm), with a form based on the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration. On March 28, 2008 (73 FR 16436), the EPA revised the O_3 standards to a level of 0.075 ppm, with a form based on the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration. These changes in the level and form of the O_3 NAAQS, along with notable decreases in O_3 levels in most parts of the U.S., have changed the landscape of O_3 NAAQS violations in the U.S. At the time of the first round of designations for the 8-hour standards (June 15, 2005), only 5 areas were classified as serious or above for the 8-hour standards as compared to 22 areas that were classified as serious or above for the 1-hour standards. While the number of serious and above areas decreased, the number of nonattainment areas remained nearly the same. In addition to the change in the landscape of O_3 nonattainment issues, much of the equipment used at PAMS sites is outdated and in need of replacement. New technologies have been developed since the inception of the PAMS program that should be considered for use in the network to simplify procedures and improve data quality. For these reasons, the EPA determined that it would be appropriate to re-evaluate the PAMS program as explained below.

In 2011, the EPA initiated an effort to re-evaluate the PAMS requirements in light of changes in the needs of PAMS data users and the improvements in monitoring technology. The EPA consulted with the Clean Air Science Advisory Committee (CASAC), Air

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Monitoring and Methods Subcommittee (AMMS) to seek advice on potential revisions to the technical and regulatory aspects of the PAMS program; including changes to required measurements and associated network design requirements. The EPA also requested advice on appropriate technology, sampling frequency, and overall program objectives in the context of the most recently revised O_3 NAAQS and changes to atmospheric chemistry that have occurred over the past 10–15 years in the significantly impacted areas. The CASAC AMMS met on May 16 and May 17, 2011, and provided a report with their advice on the PAMS program on September 28, 2011 (U.S. EPA, 2011f). In addition, the EPA met multiple times with the National Association of Clean Air Agencies (NACAA) Monitoring Steering Committee (MSC) to seek advice on the PAMS program. The MSC includes monitoring experts from various State and local agencies actively engaged in ambient air monitoring and many members of the MSC have direct experience with running PAMS sites. Specific advice obtained from the CASAC AMMS and the MSC that was considered in making the proposed changes to the PAMS requirements is discussed in the appropriate sections below.

Based on the findings of the PAMS evaluation and the consultations with the CASAC AMMS and NACAA MSC, the EPA proposed to revise several aspects of the PAMS monitoring requirements including changes in (1) network design, (2) VOC sampling, (3) carbonyl sampling, (4) nitrogen oxides sampling, and (5) meteorology measurements. The following paragraphs summarize the proposed changes, the comments received, and the final changes and supporting rationale.

1. Network Design

As discussed above, the current PAMS network design calls for two sites (a Type 2, and a Type 1 or Type 3) per PAMS area. In their report (U.S EPA, 2011f), the CASAC AMMS found ''that the existing uniform national network design model for PAMS is outdated and too resource intensive,'' and recommended ''that greater flexibility for network design and implementation of the PAMS program be transferred to state and local monitoring agencies to allow monitoring, research, and data analysis to be better tailored to the specific needs of each O_3 problem area.'' While stating that the current PAMS objectives were appropriate, the AMMS report also stated that ''objectives may need to be revised to include both a national and regional focus because national objectives may be different from regional objectives.'' The NACAA MSC also advised the EPA that the existing PAMS requirements were too prescriptive and may hinder state efforts to collect other types of data that were more useful in understanding their local O_3 problems.

The EPA agrees with CASAC that the PAMS objectives include both local and national objectives, and believes that the current PAMS network design is no longer suited for meeting either sets of objectives. As part of the PAMS evaluation, it was determined that at the national level the primary use of the PAMS data has been to evaluate photochemical model performance. Due to the locations of the current PAMS areas and the current network design, existing PAMS sites are clustered along the northeast and west coasts leading to significant redundancy in these areas and very limited coverage throughout the remainder of the country (Cavender, 2014). The resulting uneven spatial coverage greatly limits the value of the PAMS data for evaluation of model performance. CASAC (U.S. EPA, 2011f) noted the spatial coverage issue and advised that the EPA should consider requiring PAMS measurements in areas in addition to ''areas classified as serious and above for the O_3 NAAQS to improve spatial coverage.'' The EPA also agrees with CASAC and NACAA that the PAMS requirements should be revised to provide monitoring agencies greater flexibility in meeting local objectives.

The EPA proposed changes to the network design requirements to better serve both national and local objectives. The EPA proposed a two part network design. The first part of the design included a network of fixed sites (''required PAMS sites'') intended to support O_3 model development and the tracking of trends of important O_3 precursor concentrations. The second part of the network design required states with O_3 non-attainment areas to develop and implement Enhanced Monitoring Plans (EMPs) which were intended to allow monitoring agencies the needed flexibility to implement additional monitoring capabilities to suit the needs of their area.

To implement the fixed site portion of the network design, the EPA proposed to require PAMS measurements at any existing NCore site in an O_3 nonattainment area in lieu of the current PAMS network design requirements.[222] The NCore network is a multi-pollutant monitoring network consisting of 80 sites (63 urban, 17 rural) sited in typical neighborhood scale locations and supports multiple air quality objectives including some of the objectives of the PAMS program including the development and evaluation of photochemical models (including both $PM_{2.5}$ and O_3 models), development and evaluation of control strategies, and the tracking of regional precursor trends.

The EPA recognized that in limited situations existing NCore sites may not be the most appropriate locations for making PAMS measurements. For example, an existing PAMS site in an O_3 nonattainment area may be sited at a different location than the existing NCore site. In this case, it may be appropriate to continue monitoring at the existing PAMS site to support ongoing research and to maintain trends information. To account for these situations, the EPA also proposed to provide the EPA Regional Administrator the authority to approve an alternative location for a required PAMS site where appropriate. The EPA also solicited comments on alternative frameworks using other benchmarks such as attainment status or population to ensure an appropriately sized fixed PAMS monitoring network. The EPA received several comments on the proposed changes to the network design, primarily from state and local monitoring agencies. The following paragraphs summarize the major comments made on the proposed network design, our response, and final network design requirements.

Most commenters agreed with the need to revise the existing network design. One commenter agreed that ''requiring PAMS monitoring at already existing NCore locations will benefit national and local objectives to understand ozone formation and would also provide significant cost efficiencies.'' Another commenter stated that they supported the proposed changes, ''especially the flexibility provided by EMPs designed to meet local objectives and achieve a better understanding of photochemical precursors.'' Another commenter supporting the changes stated that the ''proposed network revision will provide states the flexibility to use their resources effectively.'' One commenter stated that the proposed changes ''reflect a more efficient use of state and local monitoring resources by availing

[222] The EPA noted that the proposed change would expand the PAMS applicability beyond that required in 182(c)(1) of the CAA. Thus, in this final rule, the EPA is relying on the authority provided in Sections 103(c), 110(a)(2)(B), 114(a) and 301(a)(1) of the CAA to expand the PAMS applicability to areas other than those that are serious or above O_3 nonattainment.

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monitoring agencies of existing NCore infrastructure to fulfill PAMS requirements.''

A number of concerns were also raised with the proposed network design. Several commenters stated that the proposal ''would drastically reduce the PAMS network in the Northeast.'' One commenter stated that ''this is not acceptable for the Northeast and Mid-atlantic Corridor, which requires monitoring of the complex transport from multiple large metropolitan areas in the region.'' One commenter recognized that the EPA had intended to allow states to use EMPs to address upwind and downwind data needs, but raised concerns that states with historically important upwind and downwind sites in the Ozone Transport Region [223] (OTR) may not be required to develop an EMP since those sites would be in states that are attaining the O_3 NAAQS. One commenter suggested that ''the EPA consider the entire OTR when designing a PAMS network rather than pockets of nonattainment areas in the region.'' The EPA agrees that the reduction of sites in the OTR is a potential issue and that many important existing PAMS sites would not be part of the required PAMS sites based on the proposed network design. As noted by several commenters, the EPA intended the state directed EMPs to give states flexibility in determining data needed to understand local O_3 formation, including transport in the Northeast. However, the EPA also agrees that as proposed many states in the OTR would not be required to develop EMPs and, therefore, may not be provided PAMS resources. To address these concerns and ensure adequate network coverage in the OTR, the EPA is adding a requirement that all states in the OTR develop and implement an EMP regardless of O_3 attainment status. This change will help ensure that an EMP appropriate for the entire OTR can be implemented.

Concerns were raised by some states that existing NCore sites may not be the most appropriate location for making PAMS measurements. One commenter noted that their NCore site was inland but that their ''most significant ozone problems occur along the shoreline due to transport along the lake'', and that ''the NCore site cannot provide insight into these important lakeshore ozone processes.'' Another commenter stated that ''while it was laudable to leverage sites where data is already being collected, it is unclear whether NCore sites adequately meet the objectives of the PAMS program'', and that ''the current NCore network may not be adequate to depict boundary conditions or areas of maximum emissions.'' One commenter stated that ''in some nonattainment areas an NCore site may be an appropriate location for a PAMS monitor, but in other areas it would be preferable to install the PAMS monitoring in a location downwind of a source region where higher ozone exposures occur'' and that ''State and local boundaries should not be part of the network design criteria.'' One commenter noted that while the EPA had proposed to allow waivers, it was unclear if waivers would be allowed where the alternative site was in a different CBSA or state than the required PAMS site. As stated in our proposal, the EPA recognizes that in some cases existing PAMS sites (or other sites) may be better suited to meet local and national data needs. For this reason, we had proposed to allow waivers in these situations. We do agree that it is appropriate in some cases to allow these waivers to cross CBSA and state boundaries. Therefore, we have added specific language to the final waiver provisions to clarify that waivers can be allowed to cross CBSA and state boundaries. Where a monitoring agency receives a waiver from siting a monitor in reliance on a monitor operated by a different monitoring agency (*e.g.,* across state lines), the waiver will be conditioned on the monitor being properly included in the other agency's network plan, and operated in accordance with the requirements of Part 58, including the relevant appendices.

In addition to the concerns raised about closing important existing PAMS sites discussed above, some commenters raised concerns that many of the newly required PAMS sites would be in locations that were expected to attain the revised O_3 NAAQS soon after the new sites would be installed. One commenter noted that ''requiring marginal nonattainment areas to install PAMS sites would result in a large undertaking at an area that would most likely be back in attainment at or around the time the PAMS site started collecting data.'' One commenter stated that by tying the network requirement to NAAQS attainment ''threatens to underserve areas that are very close to exceeding the revised ozone NAAQS and results in significant gaps in the spatial coverage of the PAMS network'' and ''has the potential to introduce undesirable uncertainty on the size and spatial extent of the PAMS network over the long term.'' Another commenter was concerned that the proposed network would be unstable, and would experience frequent changes as areas came into attainment or went out of attainment thus reducing the value of the data collected, and resulting in inefficient use of resources. One commenter noted that ''a more stable monitoring network design will allow for the examination of trends from spatially robust, long running sites and will allow states to firmly establish the infrastructure costs.''

The EPA noted in the proposal that the size and locations of the proposed required PAMS network is sensitive to the level of the revised O_3 NAAQS and future O_3 concentrations. We recognize and agree that if current downward trends in O_3 concentrations continue, many initially required sites may no longer be required to make PAMS measurements soon after the sites were installed. Non-required sites could be closed, soon after being installed, at the state's discretion. We agree this would result in an inefficient use of resources. We also note that if these sites were closed following a potential reclassification to attainment, the loss of those sites could lead to a network with poor spatial coverage. Therefore, the EPA is making changes to the proposed revisions to the network design to improve the stability of the fixed site network. As explained below, the final requirements are based on options for which we requested comments in the proposal and the comments we have received.

We requested comments on additional options to define the fixed PAMS network component of the new network design. These options were further discussed in a memorandum to the docket (Cavender, 2014). One option discussed was to require PAMS measurements at all NCore sites irrespective of the O_3 attainment status of the area. One commenter noted that ''requiring PAMS monitoring at all NCore sites, regardless of ozone attainment status, provides the most spatially robust and stable monitoring network.'' We noted that this requirement would result in a network of approximately 80 sites, which would be larger than the current network. In the supporting memorandum, we noted that a fixed network of 80 sites would strain existing resources and would not allow adequate resources to implement the state directed EMPs.

Another option discussed in the proposal included requiring PAMS measurements at NCore sites in O_3

[223] Section 184(c) of the CAA establishes the OTR as comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Consolidated Metropolitan Statistical Area that includes the District of Columbia.

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nonattainment areas with a population greater than 1,000,000. We noted that this option would result in a network of between 31 and 37 sites depending on the level of the revised O_3 NAAQS. We also noted that focusing the applicability of PAMS to those NCore sites in larger CBSAs would still provide the desired improvement in geographic distribution while reducing the number of required sites down to a level that would provide sufficient resources to implement the state-directed EMP portion of the network. One commenter stated that they ''supported a 1,000,000 population threshold because it would help prioritize resources to areas based on the greatest human health impacts.'' In addition, a number of commenters, while not commenting on the need for a population limit, did raise concerns about their ability to acquire and retain staff with the necessary expertise to collect PAMS measurements in less urbanized areas. As with the proposed network design, we recognize that the total number of sites and the ultimate spatial coverage under this option is also sensitive to changes in O_3 concentrations. If current downward trends in O_3 concentrations continue, many initially required sites would not be required soon after they were installed. As with the proposed option, this option could result in an unstable network resulting in an inefficient use of resources and inadequate spatial coverage to meet the network goals discussed above.

Upon further consideration and in response to the comments received, we are finalizing a network design that includes a requirement for states to make PAMS measurements at all NCore sites in CBSAs with a population of 1,000,000 people or more, irrespective of O_3 attainment status. We believe this requirement will result in an appropriately sized network (roughly 40 sites) that will provide adequate spatial coverage to meet national model evaluation needs (Cavender, 2015). Redundancy is greatly reduced while important network coverage is added in the midwest, southeast, and mountain west. The improved spatial coverage will also strengthen the EPA's ability to track trends in precursor concentrations regionally.

Because the network requirement is not tied to attainment status, this final requirement will ensure network stability and allows for more efficient use of available resources. This final requirement also removes uncertainty as to applicability and aids planning and logistics involved with implementing the new requirements. Monitoring agencies can determine the applicability of the fixed site requirements to their areas today, and begin to make plans for investments in equipment, shelter improvements, and staffing and training needs necessary to implement the fixed site requirements without having to wait for the designations process to be completed. In addition, this final requirement should alleviate concerns raised by monitoring agencies in more rural locations over the ability to attract and retain staff with the skills necessary to make PAMS measurements.

By adding the PAMS measurements to existing NCore sites, significant efficiencies can be obtained which should further reduce the costs of the fixed site network as NCore sites currently make many of the PAMS measurements. Furthermore, adding the additional PAMS measurements (*e.g.,* speciated VOCs, carbonyls, and mixing height) to existing NCore sites will improve our ability to assess other pollutants (*e.g.,* air toxics and $PM_{2.5}$).

Although, as discussed in comment and summarized above, we believe there are good reasons for not tying the requirement for fixed PAMS sites to O_3 attainment status, we continue to believe that requiring PAMS measurements in areas that historically have had low O_3 concentrations is unlikely to provide data of significant value to warrant the expense and effort of making such measurements. Therefore, we have included a provision that would allow a monitoring agency to obtain a waiver, based on Regional Administrator approval, in instances where CBSA-wide O_3 design values are equal to or less than 85% of the 8-hour O_3 NAAQS and where the site is not considered an important upwind or downwind site for other nonattainment areas. The EPA selected 85% as the threshold for this waiver provision as it has been used historically to identify locations needing additional monitoring for both the O_3 and $PM_{2.5}$ NAAQS. The EPA will work with the monitoring agencies and the Regions to help ensure consistent implementation of this waiver provision.

The second part of the proposed PAMS network design included monitoring agency directed enhanced O_3 monitoring activities intended to provide data needed to understand an area's specific O_3 issues. To implement this part of the PAMS network design, the EPA proposed to add a requirement for states with O_3 nonattainment areas to develop an EMP. The purpose of the EMP was to improve monitoring for ambient concentrations of O_3, NO_X, total reactive nitrogen (NO_y) [224], VOC, and meteorology. The EPA suggested that types of activities that might be included in the state's EMP could include additional PAMS sites (*e.g.,* upwind or downwind sites), additional O_3 and NO_X monitoring, ozonesondes or other aloft measurements, rural measurements, mobile PAMS sites, additional meteorological measurements, and episodic or intensive studies. The intent of the EMPs is to allow monitoring agencies flexibility in determining and collecting the information they need to understand their specific O_3 problems.

We received comments on the proposed requirement for an EMP in states with O_3 nonattainment areas. Most comments supported the requirement, but other comments raised a number of concerns. A number of commenters questioned the need for EMPs in Marginal and Moderate O_3 nonattainment areas. They noted that in most cases, Marginal O_3 nonattainment areas were expected to come into compliance without state-specific controls. One commenter stated that ''nonattainment areas projected to attain the standard without additional state-level actions may not need the PAMS resources and additional monitoring to develop a better understanding of their ozone issues.'' One commenter noted that ''marginal ozone nonattainment areas are given only a few requirements because it is assumed that the areas will reach attainment within three years.'' Another commenter stated ''requiring enhanced monitoring for any marginal or moderate area should only be implemented where such analyses show the need for this data.'' The EPA agrees that based on current trends in O_3 concentrations and the EPA's own projections, states in Marginal nonattainment areas likely will comply with the revised NAAQS without additional state-directed controls, and as such, an EMP is not necessary in Marginal O_3 attainment areas. Accordingly, the EPA is finalizing a requirement for EMPs in areas classified as Moderate or above O_3 nonattainment and, thereby, removing the applicability of the requirement for Marginal areas. We believe this final requirement will provide the desired flexibility to allow states to identify enhanced monitoring needs while focusing resources for EMPs in areas of greater need of enhanced monitoring data.

Commenters expressed concerns over the lack of detail on what an approvable EMP would entail. As proposed, the

[224] NO_y includes NO, NO_2, and other oxidized nitrogen compounds (NO_z).

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EMPs would be reviewed and approved by the EPA Regional Administrator as part of the annual monitoring plan review process. One commenter recommended that the "EPA detail the requirements of the EMPs for ozone nonattainment areas in future implementation guidance." One commenter stated that the "EPA should provide some coordination between regional offices and technical guidance to state agencies that would be of assistance in developing and executing the EMPs." The requirements for the EMPs were intentionally left quite general in order to maximize the flexibility for states in identifying their specific data needs. Regional approval of the plans is required to ensure the enhanced monitoring planned will be commensurate with grant funds provided for EMPs. Nonetheless, the EPA understands the need for guidance on developing EMPs and commits to working with monitoring agencies and the regions to develop appropriate guidance on developing and reviewing EMPs.

2. Speciated VOC Measurements

Measurement of speciated VOCs important to O_3 formation is a key aspect of the PAMS program. The existing PAMS requirements allow for a number of options in measuring speciated VOCs at PAMS sites which include (1) hourly measurements using an automatic gas chromatograph ("autoGC"), (2) eight 3-hour samples daily using canisters, or (3) one morning and one afternoon sample with a 3-hour or less averaging time daily using canisters plus continuous Total Non-methane Hydrocarbon (TNMHC) measurements.

The EPA believes that the current options provided for VOC measurement limit the comparative value of the data being collected, and proposed that required PAMS sites must measure and report hourly speciated VOCs, which effectively would require them to use an autoGC to measure VOCs in lieu of canisters. More complete and consistent speciated VOC data nationally would better help meet certain objectives of the PAMS program described above (*e.g.,* a speciated ambient air database useful in evaluating control strategies, analyzing emissions inventory issues, corroborating progress toward attainment, and evaluating population exposure to air toxics). Furthermore, as noted by the CASAC AMMS, hourly VOC data are "particularly useful in evaluating air quality models and performing diagnostic emission attribution studies. These data can be provided on a near real-time basis and presented along with other precursor species (*e.g.,* oxides of nitrogen and carbon monoxide) collected over similar averaging times." Longer time-averaged data are of significantly lower value for model evaluation. In addition, creating consistent monitoring requirements across the network would provide better data for analyzing regional trends and spatial patterns.

At the time the original PAMS requirements were promulgated, the canister options were included because the EPA recognized that the technologies necessary to measure hourly average speciated VOCs concentrations were relatively new and may not have been suitable for broad network use. At that time, GCs designed for laboratory use were equipped with auto-samplers designed to "trap" the VOC compounds from a gas sample, and then "purge" the compounds onto the GC column. The EPA did not believe that autoGCs were universally appropriate due to the technical skill and effort necessary at that time to properly operate an autoGC.

While the basic principles of autoGC technology have not changed, the hardware and software of modern autoGCs are greatly improved over that available at the time of the original PAMS requirements. Based on advice from the CASAC AMMS, the EPA initiated an evaluation of current autoGCs potentially suitable for use in the PAMS network. Based on the preliminary results, the EPA believes that typical site operators, with appropriate training, will have the skill necessary to operate a modern autoGC successfully. Considering the advances in autoGC technology, the added value obtained from hourly data, and the proposed move of PAMS measurements to NCore sites in O_3 nonattainment areas, the EPA proposed to require hourly speciated VOC sampling at all PAMS sites. The EPA noted that this proposed requirement would effectively prevent the use of canisters to collect speciated VOCs at the required PAMS sites but that canister sampling may continue to be an appropriate method for collecting speciated VOCs at other locations as part of discretionary monitoring designed within the EMPs.

While the EPA believes that the proposed transition to hourly speciated VOC sampling is the appropriate strategy to take advantage of improved technology and to broaden the utility of collected data, we are also mindful of the additional rigidity that the proposed mandatory use of autoGCs may have for monitoring agencies, especially those that have experience with and have established effective and reliable canister sampling programs. Therefore, the EPA requested comment on the proposed requirement for hourly VOC sampling as well as the range of alternatives that might be appropriate in lieu of a strict requirement.

The EPA received a number of comments on the requirement to measure hourly VOCs at required PAMS sites. Many commenters agreed with requiring hourly VOC data. One commenter agreed that "hourly VOC data collection is the most appropriate and useful for PAMS monitors" and that "it is only appropriate to approve an alternative data collection interval if it is believed that the high ozone in an area is due to other pollutants, such as NO_X or methane." One commenter stated they "supported the movement towards hourly PAMS VOC speciated measurements with flexibility to use canisters if programmatic or logistical needs indicate."

However, some commenters raised concerns with the hourly VOC requirement. Some commenters questioned if autoGCs would be capable of measuring important VOC species in their environment. One commenter noted that in their location (high desert) "the largest VOC present in our inventory is creosote, a compound not commonly measured with this instrumentation." One commenter stated that the "Southeastern United States is dominated by biogenic VOC emissions" and questioned "the benefits of an autoGC in understanding ozone formation in any potential nonattainment area in our State." [225] Some questioned the detection capabilities of autoGCs as compared to canister sampling. One commenter found that the method detection limit (MDL) for their canister sampling was "consistently equal to or less than the autoGC instrumentation" based on the EPA's autoGC evaluation laboratory report (RTI, 2014). Another commenter noted that the MDLs for many of the compounds and systems reported in the laboratory report were too high to be useful at PAMS sites. Another commenter stated that they found that "retention-time shifts made it difficult for instant identification of chemical peaks" and that "states should be allowed the flexibility to continue using canisters instead of autoGC."

As noted in the preamble, and the comments received, the EPA is currently completing an evaluation of

[225] The EPA notes that isoprene (the dominant biogenic compound in the Southeast) is well measured using autoGCs. The EPA is also evaluating the potential of modern autoGC's to measure alpha and beta pinene; however that work is not complete.

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commercially available autoGCs. A copy of the report for the laboratory phase of the study is available in the docket (RTI, 2014). As noted in the laboratory report, the MDL estimates made for the laboratory study were not conducted according to normal MDL testing procedures and as such the results should only be used to compare the various instruments being tested against each other.[226] As part of the evaluation, the EPA identified the manufacturer's specifications for MDL. Most of the systems that are being evaluated have a manufacturer's estimated MDL in the range of 0.1 ppb to 0.5 ppb. Based on the evaluation of MDL capabilities and typical ambient concentrations of O_3 precursors, the EPA believes that autoGCs are an appropriate method for gathering VOC data at most urban locations. However, canister sampling may be more appropriate in locations with low VOC concentrations.

For the reasons discussed above and in the proposed rule, the EPA is finalizing a requirement for hourly speciated VOC measurements at required PAMS sites. The EPA believes that hourly VOC measurements will provide a more complete and consistent speciated VOC database to help meet the PAMS program objectives described above. Hourly VOC data are particularly useful in evaluating air quality models and performing diagnostic emission attribution studies. Longer time-averaged data are of lower value for model evaluation. Consistent monitoring requirements across the network will provide better data for analyzing regional trends and spatial patterns.

However, the EPA agrees that there may be locations where an autoGC may not be the most appropriate method for VOC measurement and that it is appropriate to allow for canister sampling in limited situations. Accordingly, the EPA is adding a waiver option (to be approved by the EPA Regional Administrator) to allow three 8-hour average samples every 3rd day as an alternative in cases where VOCs are not well measured by autoGC due to low concentrations of target compounds or where the predominant VOC compounds cannot be measured using autoGC technology (*e.g.,* creosote in high desert environments). This alternative sampling frequency was selected to be consistent with the sampling frequency selected for carbonyls, which is discussed later in this preamble.

3. Carbonyl Measurements

Carbonyls include a number of compounds important to O_3 formation that cannot currently be measured using the autoGCs or canisters used at PAMS sites to measure speciated VOCs. The current method for measuring carbonyls in the PAMS program is Compendium Method TO–11A (U.S. EPA, 1999). In this method, carbonyl compounds are adsorbed and converted into stable hydrazones using dinitrophenylhydrazine (DNPH) cartridges. These cartridges are then analyzed for the individual carbonyl compounds using liquid chromatography (LC) techniques. Three carbonyls are currently required to be measured in the PAMS program—formaldehyde, acetaldehyde, and acetone.

In 2006, the EPA revised the PAMS requirements such that carbonyl sampling was only required in areas classified as serious or above nonattainment for O_3 under the 8-hour O_3 standard which effectively reduced the applicability of carbonyl sampling to a few areas in California. This change was made in recognition that there were a number of issues with Method TO–11A that raised concerns with the uncertainty in the carbonyl data being collected. These issues include interferences (humidity and O_3) and breakthrough (*i.e.,* overloading of the DNPH cartridge) at high concentrations. While solutions for these issues have been investigated, these improvements have not been incorporated into Method TO–11A.

A recent evaluation of the importance of VOCs and carbonyls to O_3 formation determined that carbonyls, especially formaldehyde, are very important to O_3 formation (Cavender, 2013). CASAC AMMS (U.S. EPA, 2011f) also noted the importance of carbonyls stating that "There are many compelling scientific reasons to measure carbonyls. They are a very important part of O_3 chemistry almost everywhere." Although the EPA recognizes the issues that have been raised about the current method of measuring carbonyls, due to the importance of carbonyls to understanding O_3 chemistry, the EPA proposed to require all required PAMS sites to measure carbonyls.

Several commenters agreed with the need for carbonyl data at PAMS sites. However, a number of commenters questioned the proposed frequency of eight 3-hour samples every day during the PAMS sampling season (June through August). Several commenters indicated that the frequency was too high. One commenter noted that the requirement would require 800 samples per season at each PAMS site and pointed out that this requirement, which was required at the inception of the PAMS program in the 1990s was "found to be prohibitively expensive, technically unsustainable, and qualitatively compromised." Another commenter stated that "this level of sampling would require a substantial amount of agency resources and seems unduly burdensome." A number of commenters also questioned the commercial availability of an 8-channel carbonyl sampler that would be needed to take eight 3-hour samples daily. In light of the comments and upon further review, the EPA agrees that the proposed frequency is unduly burdensome and is finalizing a requirement with a lower frequency.

A number of alternative frequencies were suggested in the comments. Several commenters suggested a frequency of three 8-hour samples on either a 1-in-6 day or 1-in-3 day basis. Another commenter suggested a frequency of eight 3-hour samples on a 1 in 6 day basis. The EPA notes that sampling on a 1-in-6 day frequency would lead to as little as 15 sampling days per PAMS sampling season. The EPA believes that 15 sampling days is too few to provide a meaningful representation of carbonyl concentrations over the PAMS sampling period. A sampling frequency of 1-in-3 days would lead to 30 sampling days per season with each day of the week being represented at least 4 times per sampling season. With regards to samples per day, a 3-hour sampling duration provides a better diurnal representation of carbonyl sampling compared with an 8-hour sampling duration; however 8-hour sampling can provide information useful for evaluating diurnal differences in carbonyl concentrations. Upon further consideration and in light of the comments received, the EPA is finalizing a carbonyl sampling requirement with a frequency of three 8-hour samples on a 1-in-3 day basis. This final requirement will result in approximately 90 samples per PAMS sampling season which the EPA believes is not unduly burdensome and

[226] Several factors combined to result in the high relative MDL estimates reported in laboratory report. The MDL testing in the laboratory was conducted during concurrent tests for interferences from humidity and temperature. In addition, the MDL testing was conducted at relatively high concentrations compared to the concentrations testing would be conducted at for conventional MDL testing. Finally, as noted in the laboratory report, a number of instruments were having technical difficulties during the testing which greatly impacted their MDL results. The EPA is continuing the autoGC evaluation and has conducted a field study during the summer of 2015. A final report is expected in early 2016.

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will provide a reasonable representation of carbonyl concentrations.

A number of commenters noted the ongoing development of continuous formaldehyde instruments, and recommended that EPA allow for continuous formaldehyde measurements as an alternative to the manual cartridge based TO–11A method. The EPA agrees that continuous formaldehyde, with the ability to obtain hourly averaged measurements, would be a significantly more valuable that the longer averaged measurements. As a result, the EPA has added an option to allow for continuous formaldehyde as an alternative to the carbonyl measurements using TO–11A.

4. Nitrogen Oxides Measurements

It is well known that NO and NO_2 play important roles in O_3 formation (U.S. EPA, 2013, Section 3.2.2). Under the current network design, Type 2 PAMS sites are required to measure NO_X (which by definition is the sum of NO and NO_2), and Types 1, 3, and 4 sites are required to measure NO_y. NCore sites are currently required to measure NO_y but are not required to measure NO_2 separately.

In conventional NO_X analyzers, NO_2 is determined as the difference between the measured NO and NO_X concentrations. However, due to the non-selective reduction of oxidized nitrogen compounds by the molybedenum converter used in conventional NO_X monitors, the NO_2 measurement made by conventional NO_X monitors can be biased high due to the varying presence of NOz compounds that may be reported as NO_2. The unknown bias from the NOz compounds is undesirable when attempting to understand O_3 chemistry.

Improvements in reactive nitrogen measurements have been made since the original PAMS requirements were promulgated that allow for improved NO_2 measurements. Selective photolytic converters have been developed that are not significantly biased by NOz compounds (Ryerson et al., 2000). Monitors using photolytic converters are commercially available and have been approved as FEMs for the measurement of NO_2. In addition, methods that directly read NO_2 have been developed that allow for very accurate readings of NO_2 without some of the issues inherent to the ''difference method'' used in converter-based NO_X analyzers. However, these direct reading NO_2 analyzers generally do not provide an NO estimate, and would need to be paired with a converter-based NO_X monitor or NO_y monitor in order to also measure NO.

As discussed above, the EPA is finalizing a PAMS network design such that PAMS measurements will be required at existing NCore sites in CBSAs with a population of 1,000,000 people or more. NCore sites currently are required to measure NO and NO_y. NCore sites are not currently required to measure NO_2. Due to the importance of accurate NO_2 data to the understanding of O_3 formation, the EPA proposed to require NO_2 measurements at required PAMS sites. Since existing NCore sites currently measure NO_y, either a direct reading NO_2 analyzer or a photolytic-converter NO_X analyzer could be used to meet the proposed requirement. The EPA believes conventional NO_X analyzers would not be appropriate for making PAMS measurements due to the uncertainty caused by interferences from NO_z compounds.

A number of commenters questioned the need for both NO_y and NO_2 measurements at PAMS sites. One commenter stated that ''in dense urban areas an $NO/NO_2/NO_X$ instrument may be adequate but in a more rural area an NO/NO_y instrument may be preferable.'' Another commenter stated that due to the size of the grid cells used in grid models that ''the impact of NOz interferences would be very small compared to other modeling uncertainties such as emission inventories and mixing heights.'' Another commenter suggested that ''EPA should provide clear and specific guidance on how agencies can request that the NO_y monitoring be eliminated from the NCore suite based on comparative data between the NO_2 and NO_y monitors.''

The comments suggest that the model's ability to simulate the partitioning of reactive nitrogen is unimportant because there may be other errors in the model. The EPA believes that measurements should be routinely collected so that it can be demonstrated that the chemistry, meteorology, and emissions in the model are all of sufficient reliability for use in informing air quality management decisions. Monitoring sites rarely fall into simple categories of urban or rural, and the speciation of NO_y varies considerably as a function of meteorology and time of day at a given site. The state-of-the-science in regulatory air quality modeling is such that accurate measurements of key O_3 precursors must be available to demonstrate the credibility of the model predictions. The increased availability of special field study observations is leading to increased scrutiny of the chemical mechanisms used in regulatory modeling. Comprehensive and accurate measurement sites are needed to demonstrate the adequacy of the models and to respond to these challenges.

Measurements of NO, NO_2, and NO_y concentrations are critical to understanding atmospheric aging and photochemistry. These measurements will provide essential information about whether NO_y compounds are fresh or aged which is important for understanding both local photochemistry (*i.e.* through indicator ratios to distinguish NO_X vs VOC limited conditions) as well as for characterizing transport from upwind regions. These evaluations may be conducted using observations, box modeling or through complex photochemical grid based modeling. Accurate speciated and total NO_y measurements are necessary for all three types of analysis. For these reasons, the EPA is finalizing the requirement for required PAMS sites to measure true NO_2 in addition to NO and NO_y.

5. Meteorology Measurements

The current PAMS requirements require monitoring agencies to collect surface meteorology at all required PAMS sites. As noted in the EPA's Technical Assistance Document (U.S. EPA, 1998) for the PAMS program, the PAMS requirements do not provide specific surface meteorological parameters to be monitored. As part of the implementation efforts for the original PAMS program, a list of recommended parameters was developed and incorporated into the TAD which includes wind direction, wind speed, temperature, humidity, atmospheric pressure, precipitation, solar radiation, and ultraviolet (UV) radiation. Currently, NCore sites are required to measure the above parameters with the exceptions of atmospheric pressure, precipitation, solar radiation, and UV radiation. In recognition of the importance of these additional measurements for understanding O_3 formation, the EPA proposed to specify that required PAMS sites are required to collect wind direction, wind speed, temperature, humidity, atmospheric pressure, precipitation, solar radiation, and UV radiation. Since NCore sites are currently required to measure several of these surface meteorological parameters, the net impact of the proposal was to add the requirement for the monitoring of atmospheric pressure, precipitation, solar radiation, and UV radiation at affected NCore sites. The EPA received no significant comments on this portion of the proposal, and therefore is finalizing the requirement as proposed.

The existing PAMS requirements also require the collection of upper air meteorological measurements at one site in each PAMS area. The term upper air meteorological is not well defined in the existing PAMS requirements. As part of the implementation efforts for the original PAMS program, mixing height was added to the PAMS TAD as a recommended meteorological parameter to be monitored. Most monitoring agencies installed radar profilers to meet the requirement to collect upper air meteorology. Radar profilers provide data on wind direction and speed at multiple heights in the atmosphere. Radio acoustic sounding system (RASS) profilers are often included with radar profilers to obtain atmospheric temperature at multiple heights in the atmosphere and to estimate mixing height. The EPA recognizes that the upper air data on wind speed and wind direction from radar profilers can be very useful in O_3 modeling. However, many of the current PAMS radar profilers are old and in need of replacement or expensive maintenance. In addition, the cost to install and operate radar profilers at all required PAMS sites would be prohibitive. Therefore, the EPA did not propose to add upper air wind speed and direction as required meteorological parameters to be monitored at required PAMS sites. Where monitoring agencies find the radar profiler data valuable, continued operation of existing radar profilers or the installation of new radar profilers would be appropriate to consider as part of the state's EMP.

As discussed above, mixing height is one upper air meteorological measurement that has historically been measured at PAMS sites. A number of methods can be used to measure mixing height in addition to radar profiler technology discussed above. Recent developments in ceilometer technology allow for the measurement of mixing height by changes in particulate concentrations at the top of the boundary layer (Eresmaa et al., 2006). Ceilometers provide the potential for continuous mixing height data at a fraction of the cost of radar profilers. Due to the importance of mixing height measurements for O_3 modeling, the EPA proposed to add the requirement for monitoring agencies to measure mixing height at required PAMS sites.

A number of commenters questioned the need for mixing height measurements at PAMS sites. One commenter stated, ''the photochemical modeling community has a long history of relying upon National Weather Service measurements for mixing height.'' Another commenter stated that ''in some areas of the country the models used to predict mixing height are adequate, but in other mountainous or marine areas model-predicted mixing height data is inadequate.'' Accurate estimates of mixing height are important for appropriately characterizing concentrations of O_3 and O_3 precursors. Mixing height is also important for characterizing how modeled O_3 may change as a result of changing NO_X and VOC concentrations. For instance, if the modeled mixing height is too low causing unrealistically high concentration of NO_X, then O_3 destruction could be predicted when O_3 production may be happening in the atmosphere. When this or the opposite situation exists in modeling it may lead O_3 response to emissions changes that are less reliable for air quality planning purposes. While models are believed to do a reasonable job of predicting mixing height during the day, there is considerably more uncertainty in predicting this parameter during morning and evening transition periods and at night. Model O_3 predictions are particularly sensitive to mixing height during the time periods for which uncertainty in this parameter is greatest.

Several commenters noted that nearby National Oceanic and Atmospheric Administration (NOAA) Automated Surface Observing System (ASOS) sites may be a better alternative for collection of mixing height data. As indicated in the proposal, the EPA is aware of the network of ceilometers operated by NOAA as part of ASOS. The EPA has been in discussions with NOAA regarding the potential for these systems to provide the needed mixing height data. However, the ASOS ceilometers are not currently equipped to provide mixing height data and NOAA has no current plans to measure continuous mixing height in the future. Nonetheless, the EPA will continue to work with NOAA to determine if the ASOS ceilometers can be upgraded to meet the need for mixing height data, and included proposed regulatory language that will allow states a waiver to use nearby mixing height data from ASOS (or other sources) to meet the requirement to collect mixing height data at required PAMS sites when such data are suitable and available.

The EPA is finalizing the requirement for the measurement of mixing height at required PAMS sites due to the importance of mixing height in O_3 modeling. A waiver option, to be approved by the Regional Administrator, is also being included to allow mixing height measurements to be obtained from other nearby sites (*e.g.,* NOAA ASOS sites).

6. PAMS Season

Currently, PAMS measurements are required to be taken during the months of June, July, and August. This 3-month period is referred to as the ''PAMS Season.'' As part of the PAMS re-evaluation, the EPA considered changes to the PAMS season. The 3-month PAMS season was originally selected to represent the most active period for O_3 formation. However, the EPA notes that in many areas the highest O_3 concentrations are observed outside of the PAMS season. As an example, the highest O_3 concentrations in the mountain-west often occur during the winter months. Data collected during the current PAMS season would have limited value in understanding winter O_3 episodes.

The CASAC AMMS (U.S. EPA, 2011f) noted in their report to the EPA that ''it would be desirable to extend the PAMS monitoring season beyond the current June, July, August sampling period.'' But that ''the monitoring season should not be mandated and rigid; it should be flexible and adopted and coordinated on a regional airshed basis.'' The EPA agrees with CASAC on the need for flexibility in determining when PAMS measurements should be taken to meet local monitoring needs but also agrees with CASAC that the flexibility ''should not conflict with national goals for the PAMS program.'' A significant benefit of the standard PAMS season is that it ensures data availability from all PAMS sites for national- or regional-scale modeling efforts.

While the EPA agrees with the potential benefit of extending the availability of PAMS measurements outside of the current season, we also considered the burden of requiring monitoring agencies to operate additional PAMS measurements (*e.g.,* hourly speciated VOC) for periods that in some cases, might be much longer than the current 3-month season, for example, if the PAMS season was extended to match each state's required O_3 monitoring season. Being mindful of the potential burden associated with a lengthening of the PAMS season as well as the potential benefits of the additional data, the EPA proposed to maintain the current 3-month PAMS monitoring season for required PAMS sites rather than extending the PAMS season to other periods where elevated O_3 may be expected. No significant comments were received on the proposed PAMS season, and as such, for the reasons stated here and in the proposal, the EPA is not changing the 3-month PAMS season of June, July, and August.

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The EPA believes that the 3-month PAMS season will provide a consistent data set of O_3 and O_3 precursor measurements for addressing the national PAMS objectives. Monitoring agencies are strongly encouraged to consider collecting PAMS measurements in additional periods beyond the required PAMS season as part of their EMP. The monitoring agencies should consider factors such as the periods of expected peak O_3 concentrations and regional consistency when determining potential expansion of their specific monitoring periods beyond the required PAMS season.

7. Timing and Other Implementation Issues

The EPA recognizes that the changes to the PAMS requirements will require resources and a reasonable timeline in order to be successfully implemented. The PAMS program is funded, in part, as part of the EPA's section 105 grants. The EPA believes that the current national funding level of the PAMS program is sufficient to support these final changes, but changes in the distribution of PAMS funds will need to be made. The network design changes will require some monitoring agencies to start collection of new PAMS measurements, while other monitoring agencies will see reductions in PAMS measurement requirements. The EPA will work with the NAACA, AAPCA, and other monitoring agencies to develop an appropriate PAMS grant distribution strategy.

In addition to resources, the affected monitoring agencies will need time to implement the revised PAMS requirements. For the required PAMS sites, monitoring agencies can determine now which NCore sites will be required to make PAMS measurements based on readily available census data. However, monitoring agencies will still need time to evaluate and seek approval for alternative sites or alternative VOC methods. In addition, monitoring agencies will need time to make capital investments (primarily for the installation of autoGCs, NO_2 monitors, and ceilometers), prepare appropriate QA documents, and develop the expertise needed to successfully collect PAMS measurements via training or otherwise. In order to ensure monitoring agencies have adequate time to plan and successfully implement the revised PAMS requirements, the EPA is requiring that monitoring agencies identify their plans to implement the PAMS measurements at NCore sites in their Annual Network Plan due July 1, 2018, and to begin making PAMS measurements at NCore sites by June 1, 2019. The EPA believes some monitoring agencies may be able to begin making PAMS measurements sooner than June 2019 and encourages early deployment where possible.

Monitoring agencies will need to wait until O_3 designations are made to officially determine the applicability of the EMP requirement. The EPA proposed to allow two years after designations to develop EMPs, and that the EMPs would be submitted as part of their Annual Network Plan. Several commenters stated that due to the level of planning and coordination required for the EMPs, that the plans should instead be included as part of the 5-year network assessment. While the EPA agrees that the EMPs will require a substantial amount of planning and coordination, the next 5 year network assessment will not be due until July 1, 2020—nearly 5 years from the date of this final rulemaking. The EPA believes that it would be inappropriate to wait 5-years from the date of this rulemaking to develop plans for enhanced O_3 monitoring. In addition, the EPA believes that the first round of EMP development should receive additional focus and review that may not be afforded as part of the larger network assessment. Finally, most monitoring agencies will be aware of their likely O_3 attainment status well in advance of the official designations. In order to ensure timely development of the initial EMPs, the EPA is requiring affected monitoring agencies to submit their initial EMPs no later than two years following designations. States in the OTR do not need to wait until designations to determine EMP applicability and may not be classified as Moderate or above. As such, the final rule includes a requirement for states in the OTR to submit their initial EMPs by October 1, 2019 (which is consistent with the expected timeline for the remaining EMPs). However, subsequent review and revisions to the EMPs are to be made as part of the 5-year network assessments beginning with the assessments due in 2025.

D. Addition of a New FRM for O_3

The use of FRM analyzers for the collection of air monitoring data provides uniform, reproducible measurements of concentrations of criteria pollutants in ambient air. FRMs for various pollutants are described in several appendixes to 40 CFR part 50. For most gaseous criteria pollutants (including O_3 in Appendix D of part 50), the FRM is described as a particular measurement principle and calibration procedure to be implemented, with further reference to specific analyzer performance requirements specified in 40 CFR part 53.

The EPA allows new or alternative monitoring technologies—identified as FEMs—to be used in lieu of FRMs, provided that such alternative methods produce measurements closely comparable to corresponding FRM measurements. Part 53 sets forth the specific performance requirements as well as the performance test procedures required by the EPA for determining and designating both FRM and FEM analyzers by brand and model.

To be used in a determination of compliance with the O_3 NAAQS, ambient O_3 monitoring data must be obtained using either a FRM or a FEM, as defined in parts 50 and 53. For O_3, nearly all the monitoring methods currently used by state and local monitoring agencies are FEM (not FRM) continuous analyzers that utilize an alternative measurement principle based on quantitative measurement of the absorption of UV light by O_3. This type of O_3 analyzer was introduced into monitoring networks in the 1980s and has since become the predominant type of method used because of its all-optoelectronic design and its ease of installation and operation.

The existing O_3 FRM specifies a measurement principle based on quantitative measurement of chemiluminescence from the reaction of ambient O_3 with ethylene (ET–CL). Ozone analyzers based on this FRM principle were once widely deployed in monitoring networks, but now they are no longer used for routine O_3 field monitoring because readily available UV-type FEMs are substantially less difficult to install and operate. In fact, the extent of the utilization of UV-type FEMs over FRMs for O_3 monitoring is such that FRM analyzers have now become commercially unavailable. The last new commercial FRM analyzer was designated by the EPA in 1979. The current list of all approved FRMs and FEMs capable of providing ambient O_3 data for use in NAAQS attainment decisions may be found on the EPA's Web site and in the docket for this action (U.S. EPA, 2014e). However, that list does not indicate whether or not each listed method is still commercially available.

1. Proposed Changes to the FRM for O_3

Although the existing O_3 FRM is still a technically sound methodology, the lack of commercially available FRM O_3 analyzers severely impedes the use of FRM analyzers, which are needed for quality control purposes and as the standard to which candidate FEMs are

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required to be compared. Therefore, the EPA proposed to establish a new FRM measurement technique for O_3 based on NO-chemiluminescence (NO–CL) methodology. This new chemiluminescence technique is very similar to the existing ET–CL methodology with respect to operating principle, so the EPA proposed to incorporate it into the existing O_3 FRM as a variation of the existing ET–CL methodology, coupled with the same existing FRM calibration procedure.

A revised Appendix D to 40 CFR part 50 was proposed to include both the original ET–CL methodology as well as the new NO–CL methodology, such that use of either measurement technique would be acceptable for implementation in commercial FRM analyzers. Currently, two O_3 analyzer models (from the same manufacturer) employing the NO–CL methodology have been designated by the EPA as FEMs and would qualify for re-designation as FRMs under the revised O_3 FRM. The rationale for selecting the new NO–CL FRM methodology, including what other methodologies were also considered, and additional information to support its selection are discussed in the preamble to the proposal for this action (79 FR 75366–75368). No substantive change was proposed to the existing O_3 FRM calibration procedure, which would be applicable to both chemiluminescence FRM methodologies.

The proposed FRM in part 50, Appendix D also included numerous editorial changes to provide clarification of some provisions, some revised wording, additional details, and a more refined numbering system and format consistent with that of two other recently revised FRMs (for SO_2 and CO).

As noted in the proposal, there is substantial similarity between the new and previously existing FRM measurement techniques, and comparative field data show excellent agreement between ambient O_3 measurements made with the two techniques (U.S. EPA 2014f). Therefore, the EPA believes that there will be no significant impact on the comparability between existing ambient O_3 monitoring data based on the original ET–CL methodology and new monitoring data that may be based on the NO–CL methodology.

The proposed FRM retains the original ET–CL methodology, so all existing FEMs, which were designated under part 53 based on demonstrated comparability to that ET–CL methodology, will retain their FEM designations. Thus, there will be no negative consequences or disruption to monitoring agencies, which will not be required to make any changes to their O_3 monitors due to the revised O_3 FRM. New FEMs would be designated under part 53, based on demonstrated acceptable comparability to either FRM methodology.

2. Comments on the FRM for O_3

Comments that were received from the public on the proposed new O_3 FRM technique are addressed in this section. Most commenters expressed general support for the proposed changes, although a few commenters expressed some concerns. The most significant issue discussed in comments was the relatively small but nevertheless potentially significant interference of water vapor observed in the ET–CL technique. As some comments pointed out, this interference is positive and could possibly affect NAAQS attainment decisions. The available NO–CL FEM analyzers include a sample dryer, which minimizes this interference. As noted previously, very few, if any, ET–CL FRM analyzers are still in operation. The ET–CL (with and without a sample dryer), the proposed NO–CL FRM, and all designated FEM analyzers have demonstrated compliance with the substantially reduced water vapor interference equivalent limit specified in 40 CFR part 53.

The proposed FRM mentioned the need for a sample air dryer for both ET–CL and NO–CL FRM analyzers. In response to these comments, the wording of the ET–CL FRM has been augmented to clarify the requirement for a dryer in all newly designated FRMs (the only change being made by the EPA to the existing ET–CL FRM as proposed). Also, the interference equivalent limit for water vapor in part 53 was proposed to be substantially reduced from the current 0.02 ppm to 0.002 ppm. The interference equivalent test for water vapor applicable to the new NO–CL candidate FRM analyzers (specified in Table B–3 of part 53) was proposed to be more stringent than the corresponding existing test for ET–CL FRM analyzers by requiring that water vapor be mixed with O_3. This mixing requirement was not part of the existing test for ET–CL candidate analyzers (denoted by footnote 3 in Table B–3). However, in further response to these commenters' concerns, the EPA has modified Table B–3 to extend this water vapor mixing requirement to newly designated ET–CL analyzers, as well. These measures should insure that potential water vapor interference is minimized in all newly designated FRM analyzers.

Several comments indicated concern that currently-designated FEM analyzers retain their designation without retesting if the new FRM were promulgated. The current ET–CL FRM is being retained; therefore, it is not necessary to make these new requirements retroactive to existing designated FEM analyzers. The existing FEM analyzers will not be required to be retested, and their FEM designation will be retained so that there will be no disruption to current monitoring networks.

Although beyond the scope of this rulemaking, other comments concerned potential hazards of the NO compressed gas supply required for NO–CL analyzer operation, and the current non-availability of a photolytic converter to provide an alternative source of NO from a less hazardous nitrous oxide gas supply. With regard to the photolytic converter, the EPA would approve such a converter as a source of NO if requested by an FRM analyzer manufacturer, upon demonstration of adequate functionality.

A few commenters liked the ''scrubberless UV absorption'' (SL–UV) measurement technique. The EPA has identified the SL–UV method as a potentially advantageous candidate for the O_3 FRM, but could not propose adopting it until additional test and performance information becomes available. A related comment requested clarification that promulgation of the proposed revised FRM would not preclude future consideration of other O_3 measurement techniques such as SL–UV. In response, the EPA can always consider new technologies for FRMs under 40 CFR 53.16 (Supersession of reference methods). However, a revised or amended FRM that included the SL–UV technique, as set forth in Appendix D of 40 CFR part 50, would have to be promulgated as part of a future rulemaking, before a SL–UV analyzer could be approved as an FRM under 40 CFR part 53.

One comment suggested that the value for the absorption cross section of O_3 at 254 nm used by the FRM's calibration procedure should be changed. The comment indicated that the nearly 2% difference effectively lowers the O_3 NAAQS by that amount. Using the corrected value would resolve much of the difference observed between O_3 measurements calibrated against the UV standard reference photometer versus those calibrated using NO gas phase titration and it would allow the EPA to adopt the less complex and more economical Gas Phase Titration (GPT) technique as the primary calibration standard for the

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FRM. The EPA will await the results of further studies determining the value of the O_3 cross section at 254 nm before making a change to the calibration procedures and will not finalize changes to the calibration procedures in this final rule.

E. Revisions to the Analyzer Performance Requirements

1. Proposed Changes to the Analyzer Performance Requirements

In close association with the proposed O_3 FRM, the EPA also proposed changes to the associated analyzer performance requirements for designation of FRMs and FEMs for O_3, as set forth in 40 CFR part 53. These changes were largely confined to Table B–1, which specifies performance requirements for FRM and FEM analyzers for SO_2, CO, O_3, and NO_2, and to Table B–3, which specifies test concentrations for the various interfering agent (interferent) tests. Minor changes were also proposed for Figure B–5 and the general provisions in subpart A of part 53. All of these proposed changes are described and discussed more fully in the preamble to the proposal for this action (79 FR 75368–75369).

Modest changes proposed for Table B–3 would add new interferent test concentrations specifically for NO–CL O_3 analyzers, which include a test for NO_2 interference.

Several changes to Table B–1 were proposed. Updated performance requirements for ''standard range'' analyzers were proposed to be more consistent with current O_3 analyzer performance capabilities, including reduced limits for noise allowance, lower detectable limit (LDL), interference equivalent, zero drift, span drift, and lag, rise, and fall times. The previous limit on the total of all interferents was proposed to be withdrawn as unnecessary and to be consistent with that same change made previously for SO_2 and CO analyzers. Also, the span drift limit at 20% of the upper range limit (URL) was proposed to be withdrawn because it has similarly been shown to be unnecessary and to maintain consistency with that same change made previously for SO_2 and CO analyzers.

The form of the precision limits at both 20% and 80% of the URL was proposed to be changed from ppm to percent. The proposed new limits (in percent) were set to be equivalent to the previously existing limits (in ppm) and thus remain effectively unchanged. This change in form of the precision limits in Table B–1 has been previously made for SO_2 and CO analyzers, and was proposed to extend also to analyzers for NO_2, (again with equivalent limits) for consistency and to simplify Table B–1 across all types of analyzers to which the table applies. A new footnote proposed for Table B–1 clarifies the new form for precision limits as ''standard deviation expressed as percent of the URL.'' Also proposed was a revision to Figure B–5 (Calculation of Zero Drift, Span Drift, and Precision) to reflect the changes proposed in the form of the precision limits and the withdrawal of the limits for total interference equivalent.

Concurrent with the proposed changes to the performance requirements for candidate O_3 analyzers, the EPA conducted a review of all designated FRM and FEM O_3 analyzers currently in production or being used, and verified that all meet the proposed new performance requirements. Therefore, none would require withdrawal or cancellation of their current FRM or FEM respective designations.

Finally, the EPA proposed new, optional, ''lower range'' performance limits for O_3 analyzers operating on measurement ranges lower (*i.e.,* more sensitive) than the standard range specified in Table B–1. The new performance requirements are listed in a new ''lower range'' column in Table B–1 and will provide for more stringent performance in applications where more sensitive O_3 measurements are needed.

Two minor changes were proposed to the general, administrative provisions in Subpart A of part 53. These include an increase in the time allowed for the EPA to process requests for approval of modifications to previously designated FRMs and FEMs in 53.14 and the withdrawal of a requirement for annual submission of Product Manufacturing Checklists associated with FRMs and FEMs for $PM_{2.5}$ and $PM_{10-2.5}$ in 53.9. No comments were received on these proposed changes and the EPA will be finalizing these revisions in this rulemaking.

2. Comments on the Analyzer Performance Requirements

Several comments were received related to the proposed changes to the analyzer performance requirements of part 53, and most were supportive. Comments from a few monitoring agencies suggested that the more stringent performance requirements proposed might be difficult to achieve or would increase monitor maintenance and cost. The EPA is also clarifying that these requirements apply only to the performance qualification requirements for designations of new FRM and FEM analyzers and will have no impact on a monitoring agency's operation of existing O_3 analyzers.

More specific comments from an analyzer manufacturer pointed out that the proposed lower limits for noise and LDL may be too stringent, the former because low-cost portable analyzers may have shorter absorption cells, and the latter because of limitations of current calibration technology. After further consideration of available analyzer performance data in light of these comments, the EPA agrees and is changing the noise limits from the proposed values of 1 ppb and 0.5 ppb (for the standard and lower ranges, respectively) to 2.5 ppb and 1 ppb (respectively). The EPA is also changing the LDL limit from the proposed values of 3 ppb and 1 ppb (respectively) to 5 ppb and 2 ppb (respectively). These new limits are still considerably more stringent than the previous limits (for the standard range) and are also consistent with those recommended by the commenter and the current performance capabilities of existing analyzer/calibration technology.

This commenter also pointed out that the proposed lower limit for 12-hour zero drift, together with the way the prescribed test is carried out, resulted in the test being dominated by analyzer noise rather than drift. The EPA agrees with this comment in general but believes that further study is needed before any specific changes can be proposed for the 12-hour zero drift test, particularly since any such changes would affect analyzers for other gaseous pollutants, as well.

Other comments suggested that there was no need for the proposed new, low-range performance requirements, because of cost and that available calibrators would be inadequate for calibration of such low ranges. The EPA disagrees with these comments and believes, as noted in the proposal preamble, that there is a definite need for low-level O_3 measurements in some applications and that suitable calibration for such low-level measurement ranges can be adequately carried out. As stated previously, the new ''low range'' specifications for O_3 analyzers are optional.

Several comments pointed out some typographical errors related to footnotes in Table B–3, as proposed; these errors have been corrected in the version of Table B–3 being finalized today.

EPA is finalizing the proposed amendments to both the O_3 FRM in Appendix D of part 50 and provisions in part 53, modified as described above, in response to the comments received.

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VII. Grandfathering Provision for Certain PSD Permits

This section addresses the grandfathering provision for certain Prevention of Significant Deterioration (PSD) permit applications that is being finalized in this rule. Section VIII.C of this preamble contains a description of the PSD and Nonattainment New Source Review (NNSR) permitting programs and additional discussion of the implementation of those programs for the O_3 NAAQS.

A. Summary of the Proposed Grandfathering Provision

The EPA proposed to amend the PSD regulations to add a transition plan that would address the extent to which the revised O_3 NAAQS will apply to pending PSD permit applications. This transition plan is reflected in a grandfathering provision that applies to permit applications that meet certain milestones in the review process prior to either the signature date or effective date of the revised O_3 NAAQS. Absent such a grandfathering provision in the EPA's regulations, the EPA interprets section 165(a)(3)(B) of the CAA and the implementing PSD regulations at 40 CFR 52.21(k)(1) and 51.166(k)(1) to require that PSD permit applications include a demonstration that emissions from the proposed facility will not cause or contribute to a violation of any NAAQS that is in effect as of the date the PSD permit is issued. The proposal included a grandfathering provision that would enable eligible PSD applications to make the demonstration that the proposed project would not cause or contribute to a violation of any NAAQS with respect to the O_3 NAAQS in effect at the time the relevant permitting benchmark for grandfathering was reached, rather than the revised O_3 NAAQS. We proposed that the grandfathering provision would apply specifically to either of two categories of pending PSD permit applications: (1) Applications for which the reviewing authority has formally determined that the application is complete on or before the signature date of the final rule revising the O_3 NAAQS; and (2) applications for which the reviewing authority has first published a public notice of the draft permit or preliminary determination before the effective date of the revised NAAQS.

In the proposal, we also noted that for sources subject to the federal PSD program under 40 CFR 52.21, the EPA and air agencies that have been delegated authority to implement the federal PSD program for the EPA would apply the grandfathering provision to any PSD application that satisfies either of the two criteria that make an application eligible for grandfathering. Accordingly, if a particular application does not qualify under the first criterion based on a complete application determination, it may qualify under the second criterion based on a public notice announcing the draft permit or preliminary determination. Conversely, a source may qualify for grandfathering under the first criterion, even if it does not satisfy the second.

The EPA also proposed revisions to the PSD regulations at 40 CFR 51.166 that would afford air agencies that issue PSD permits under a SIP-approved PSD permit program the discretion to adopt provisions into the SIP that allow for grandfathering of pending PSD permits under the same circumstances as set forth in the federal PSD regulations. With regard to implementing the grandfathering provision, we also explained that air agencies with EPA-approved PSD programs in their SIPs would have additional flexibility for implementing the proposed grandfathering provision to the extent that any alternative approach is at least as stringent as the federal provision. In addition, the proposal recognized that some air agencies do not make formal completeness determinations; thus, only the latter criterion based on the issuance of a public notice would be relevant in such cases and the state could elect to adopt only that criterion into its SIP. Accordingly, the EPA proposed to add a grandfathering provision to 40 CFR 51.166 containing the same two criteria as proposed for 40 CFR 52.21.

B. Comments and Responses

Many of the comments supported the concept of grandfathering. Some of these comments, mostly by state and local air agencies, supported the grandfathering provision as proposed. Many others recommended alternative approaches to grandfathering based on several different dates. Several comments recommended that air agencies be allowed to grandfather certain PSD permit applications and issue a PSD permit based on the 2008 O_3 NAAQS after the area is designated nonattainment for the revised O_3 NAAQS. An opposing set of comments, representing a coalition of eight environmental groups and one health advocacy group, strongly objected to the proposal for grandfathering, claiming that the EPA did not have any authority under the CAA to exempt or grandfather permit applicants from the statutory PSD permitting requirements. We are addressing some of these comments below and others in the Response to Comment Document that is included in the docket for this rule.

Comments that recommended broadening the scope of the proposed grandfathering provision suggested a variety of approaches. Some air agency and industry comments recommended that the EPA adopt a grandfathering provision applicable only to those PSD applications for which the reviewing authority has determined the application to be complete on or before the signature date of the revised NAAQS. Other air agency and industry comments recommended that grandfathered status be determined only on the basis of whether the relevant permitting milestone has been achieved by the effective date of the revised NAAQS.

The EPA disagrees with these comments; the final rule uses separate dates for the two grandfathering milestones, as proposed. If the effective date of the revised NAAQS were used as the date for the complete application milestone, this could lead to pressure on state permitting authorities to prematurely issue completeness determinations in order to qualify for the grandfathering provision in the time period between signature of this final rule and the effective date. Using the signature date of the revised O_3 NAAQS as the date for the grandfathering milestone based on the completeness determination is thus intended to help preserve the integrity of the completeness determination process. Permit applications that have not yet been determined complete can be supplemented or revised to address the revised O_3 standards before the completeness determination is issued. Conversely, the amount and type of work required for a preliminary determination or a draft permit reduces the risk that such a document would be released prematurely merely to qualify for grandfathering. Similarly, because these documents are released for the purpose of providing an adequate opportunity for public participation in the permitting process, it would not behoove a reviewing authority to precipitately release such documents merely to satisfy the grandfathering milestone. Accordingly, the EPA does not have the same concerns about using the effective date of this final rule for the preliminary determination or draft permit milestone and further finds it reasonable to provide additional time for satisfying this milestone. Moreover, using the proposed milestones and corresponding dates is consistent with the milestones and corresponding dates that were used in the grandfathering provisions for the 2012 $PM_{2.5}$ NAAQS.

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Several other comments recommended that the grandfathering provision apply to all PSD applications for which a final PSD permit will be issued prior to the effective date of the area designations for the revised NAAQS. Some of these comments explained that without some transition provisions in the final rule, it may be impossible for a source to demonstrate attainment if the current ambient air monitoring data indicates a revised, lowered standard is not being met. The comments also suggested that the extended period for grandfathering a source from the revised NAAQS would provide states with additional time to establish offset banks or similar systems for new nonattainment areas.

Other comments recommended that air agencies be allowed to grandfather either all or certain PSD permit applications received before the effective date of the final nonattainment designations for the revised O_3 NAAQS. These comments supported allowing air agencies to issue PSD permits to grandfathered sources even after the area in which the source proposes to locate is designated nonattainment for the revised O_3 NAAQS. One comment saw this as being necessary because the development of the regulatory framework that will support the revised NAAQS, such as development of a credit market or even a transition into NNSR permitting, does not instantaneously accompany the revised standard. Hence, the comment added that ''[d]uring the Interim Period (the time between the revision of the NAAQS rule and development of the regulatory framework) the project may be unable to secure offsets and no offsets would be available for purchase.'' Another comment explained that the extended period for grandfathering sources from the revised O_3 NAAQS was needed to ''minimize disruption to complex projects that may have been under development since before the EPA published the proposed NAAQS revision.'' This comment noted the ''PSD projects commonly undergo years of engineering and other development resources before an air permit application can be prepared.''

The EPA does not agree with the comments recommending that the EPA use a date after the effective date of the revised O_3 NAAQS as the date by which the permit application must reach the relevant milestone to qualify for grandfathering. The EPA does not believe it is appropriate to unreasonably or unnecessarily delay implementation of these revised standards under the PSD program. As explained in more detail below, the purpose of the grandfathering provision is to provide a reasonable transition mechanism for certain PSD applications and the EPA believes that the milestones proposed and finalized here strike the appropriate balance in providing for such a reasonable transition. Moreover, in some cases, some of these recommended approaches could enable a situation where a PSD permit would be issued to a source during a future period when the area is designated nonattainment for the revised O_3 NAAQS. As explained below, the EPA does not believe that this specific outcome is permissible under the CAA.

The EPA does not agree with the comments suggesting that the grandfathering provision should be expanded to apply to any PSD application received before the effective date of the final nonattainment designations for the revised O_3 NAAQS. Because the process for reviewing PSD permit applications and issuing a final PSD permit is time consuming, such an approach could allow issuance of PSD permits to grandfathered sources even after the area in which the source proposes to locate is designated nonattainment for the revised O_3 NAAQS. The EPA does not agree that grandfathering should be extended in a way that would allow a source located in an area designated as nonattainment for a pollutant at the time of permit issuance to obtain a PSD permit for that pollutant rather than a NNSR permit. The EPA does not interpret the CAA or its implementing regulations to allow such an outcome. The PSD requirements under CAA section 165 only apply in areas designated attainment or unclassifiable for the pollutant. *Alabama Power* v. *Costle,* 636 F.2d 323, 365–66, 368 (D.C. Cir. 1980). Accordingly, the PSD implementing regulations at 40 CFR 52.21(i)(2) contain an exemption that provides that the substantive PSD requirements shall not apply to a pollutant if the owner or operator demonstrates that the facility is located in an area designated nonattainment for that pollutant under CAA section 107 of the Act. *See also* 40 CFR 51.166(i)(2) (allowing for the same exemption in SIP-approved PSD permitting programs). In addition, under CAA section 172(c)(5) implementation plans must require that permits issued to new or modified stationary sources ''anywhere in the nonattainment area'' meet the requirements of CAA section 173, which contains the NNSR permit requirements. *See* 40 CFR part 51, Appendix S, IV.A (providing that, if a major new source or major modification that would locate in an area designated as nonattainment for a pollutant for which the source or modification would be major, approval to construct may be granted only if the specific conditions for NNSR are met, including obtaining emission offsets and an emission limitation that specifies the lowest achievable emissions rate). Moreover, given the adverse air quality conditions that already exist in a nonattainment area and the congressional directive to reach attainment as expeditiously as practicable, construction of a major stationary source that significantly increases emissions in such an area should be expected to address all of the NNSR requirements, which are designed to ensure that a new or modified major stationary source will not interfere with reasonable progress toward attainment, even if this could cause delay to the permit applicant.

With respect to the comments that suggested the effective date of the NAAQS should be used as the date for both milestones, the EPA does not agree that such a change is necessary. The purpose of the grandfathering provision is to provide a reasonable transition mechanism in the following circumstances: first, the PSD application is one for which both the applicant and the reviewing authority have committed substantial resources; and, second, this situation is one where the need to satisfy the demonstration requirement under CAA section 165(a)(3) could impact the reviewing authority's ability to meet the statutory deadline for issuing a permit within one year of the completeness determination. In situations where the reviewing authority has not yet issued a completeness determination as of the signature date of the revised O_3 NAAQS, both the permit applicant and the reviewing authority have sufficient notice of the revised standard so that it can be addressed before the completeness determination is issued and the one-year clock begins to run. The grandfathering provision issued in this rulemaking is crafted to draw a reasonable balance that accommodates the requirements under both CAA sections 165(a)(3) and 165(c). Any modification of the dates further than is necessary to accommodate these concerns could upset this balance.

With respect to the comments that suggested adopting a grandfathering provision applicable only to those PSD applications for which the reviewing authority has determined the application to be complete on or before the signature date of the revised NAAQS, the EPA is not making this change because we understand that not all reviewing authorities issue formal completeness determinations. Including

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a grandfathering provision based on the publication of a public notice of the draft permit or preliminary determination provides a reasonable transition mechanism for PSD applications in situations where the reviewing authority does not issue formal completeness determinations, but the applicant and the reviewing authority have both committed substantial resources to the pending permit application at the time the revisions to the O_3 NAAQS are finalized.

An opposing set of comments—submitted by a consortium of eight environmental groups and one health advocacy group—challenged the proposed grandfathering provision on the basis that the EPA did not have the legal authority to grandfather sources from PSD requirements. These commenters argued that the plain language of CAA section 165 forecloses the EPA's proposed approach and raised several other legal considerations. The EPA disagrees with these comments, including the interpretations of the CAA that they offer. As summarized in the rationale for the final action below in section VII.C of this preamble, the EPA believes that the CAA provides it authority and discretion to establish a PSD grandfathering provision such as the one being adopted today through a rulemaking process. The EPA is providing a further, detailed analysis fully responding to this set of comments, as well as other comments related to the grandfathering provision, in the Response to Comment Document in the docket for this rule.

C. Final Action and Rationale

After consideration and evaluation of all the public comments received on the grandfathering provision, the EPA is finalizing this provision as proposed, with minor revisions that enhance the clarity of the grandfathering provision, without changing its substantive effect. While these revisions lead to slight differences in wording for the grandfathering provision for the 2012 $PM_{2.5}$ NAAQS and the grandfathering provision finalized in this rulemaking, those differences are not intended to create a different meaning; rather, the grandfathering provision finalized in this rulemaking is intended to have the same substantive effect and meaning for the revised O_3 standards as the grandfathering provision for the 2012 $PM_{2.5}$ NAAQS had for the revised PM standards. Other than those clarifying revisions, this final rule includes the same rule language for the grandfathering provision as previously proposed for the PSD regulations at 40 CFR 52.21(i)(12) and 51.166(i)(11), respectively. The provision in the final rule reflects the same two milestones and corresponding dates as the proposed grandfathering provision. Thus, under the grandfathering provision as finalized, either of the following two categories of pending PSD permit applications would be eligible for grandfathering: (1) Applications for which the reviewing authority has formally determined that the application is complete on or before the signature date of the revised O_3 NAAQS, or (2) applications for which the reviewing authority has first published a notice of a draft permit or preliminary determination before the effective date of the revised O_3 NAAQS. The EPA believes that it continues to be appropriate to include the two proposed milestones for pending permit applications to be eligible for grandfathering. While a completeness determination is often the first event, some air agencies do not determine applications complete as part of their permit process.

Under 40 CFR 52.21, a permit application may qualify for grandfathering under either of the two sets of milestones and dates contained in the provision. Where the EPA is the reviewing authority, the EPA intends to apply the grandfathering provision to PSD applicants pursuant to PSD regulations at 40 CFR 52.21 primarily through the use of the completeness determination milestone because the EPA Regional Offices make a formal completeness determination for any PSD application that they receive and review. The EPA is including the second criterion in 40 CFR 52.21 so that pending applications can still qualify for grandfathering under the second criterion if any air agency that incorporates 40 CFR 52.21 into a SIP-approved program does not make formal completeness determinations as part of its permit review process.

The EPA is also amending the PSD regulations at 40 CFR 51.166 to enable states and other air agencies that issue PSD permits under SIP-approved PSD programs to adopt a comparable grandfathering provision. Nevertheless, such air agencies have discretion to not grandfather PSD applications or to apply grandfathering under their approved PSD programs in another manner as long as that program is at least as stringent as the provision being added to 40 CFR 51.166. Accordingly, an air agency may elect to rely on both sets of milestones and dates or it may grandfather on the sole basis of only one set. However, the EPA anticipates that once a decision is made concerning the use of either set of milestones and dates, the air agency will apply grandfathering consistently to all pending PSD permit applications.

As explained in more detail in the proposal, absent a regulatory grandfathering provision, the EPA interprets section 165(a)(3)(B) of the CAA and the implementing PSD regulations at 40 CFR 52.21(k)(1) and 51.166(k)(1) to require that PSD permit applications include a demonstration that emissions from the proposed facility will not cause or contribute to a violation of any NAAQS that is in effect as of the date the PSD permit is issued. However, reading CAA section 165(a)(3)(B) in context with other provisions of the Act and the legislative history, the EPA interprets the Act to provide the EPA with authority to establish grandfathering provisions through regulation. The EPA has explained its interpretation of its authority to promulgate grandfathering provisions in previous rulemaking actions, most recently in the rule establishing the grandfathering provision for the 2012 $PM_{2.5}$ NAAQS (78 FR 3086, 3254–56, January 15, 2013), as well as in the proposal for this final action. The EPA is providing additional discussion of this authority in the Response to Comment Document contained in the docket for this final action.

To summarize briefly, the addition of this grandfathering provision is permissible under the discretion provided by the CAA for the EPA to craft a reasonable implementation regulation that balances competing objectives of the statutory PSD program found in CAA section 165. Specifically, section 165(a)(3) requires a permit applicant to demonstrate that its proposed project will not cause or contribute to a violation of any NAAQS, while section 165(c) requires that a PSD permit be granted or denied within one year after the permitting authority determines the application for such permit to be complete. Section 109(d)(1) of the CAA requires the EPA to review existing NAAQS and make appropriate revisions every five years. When these provisions are considered together, a statutory ambiguity arises concerning how the requirements under CAA section 165(a)(3)(B) should be applied to a limited set of pending PSD permit applications when the O_3 NAAQS is revised. The Act does not clearly address how the requirements of CAA section 165(a)(3)(B) should be met for PSD permit applications that are pending when the NAAQS are revised, particularly when the EPA also determines that complying with the

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demonstration requirement for the revised NAAQS could hinder compliance with the requirement under section 165(c) to issue a permit within one year of the completeness determination for a certain subset of pending permits. The CAA also does not address how the requirements of CAA sections 165(a)(3) and 165(c) should be balanced in light of the statutory requirement to review the NAAQS every five years. As Congress has not spoken precisely to this issue, the EPA has the discretion to apply a permissible interpretation of the Act that balances the statutory requirements to make a decision on a permit application within one year and to ensure the new and modified sources will only be authorized to construct after showing they can meet the substantive permitting criteria. *See Chevron, U.S.A., Inc.* v. *Natural Res. Def. Council, Inc.,* 467 U.S. 837, 843–44 (1984).

In addressing these gaps in the CAA and the tension that may arise in section 165 in these circumstances, the EPA also applies CAA section 301, where the Administrator is authorized ''to prescribe such regulations as are necessary to carry out his functions under this chapter.'' Sections 165(a)(3) and 165(c) of the CAA make clear that the interests behind CAA section 165 include both protection of air quality and timely decision-making on pending permit applications. The legislative history illustrates congressional intent to avoid delays in permit processing. S. Rep. No. 94–717, at 26 (1976) (''nothing could be more detrimental to the intent of this section and the integrity of this Act than to have the process encumbered by bureaucratic delay''). Thus, when read in combination, these provisions of the CAA provide the EPA with the discretion to issue regulations to grandfather pending permit applications from having to address a revised NAAQS where necessary to achieve both CAA objectives—to protect the NAAQS and to avoid delays in processing PSD permit applications. Accordingly, the EPA is seeking in this action to balance the requirements in the CAA to make a decision on a permit application within one year and to ensure that new and modified sources will only be authorized to construct after showing they can meet the substantive permitting criteria that apply to them. The EPA is achieving this balance by determining through rulemaking which O_3 NAAQS apply to certain permit applications that are pending when the EPA finalizes the revisions to the O_3 NAAQS in this final rule. We are clarifying, for the limited purpose of satisfying the requirements under section 165(a)(3)(B) for those permits, which O_3 NAAQS are applicable to those permit applications and must be addressed in the source's demonstration that its emissions do not cause or contribute to a violation of the NAAQS.

This approach is consistent with a recent opinion by the U.S. Court of Appeals for the Ninth Circuit, which recognized the EPA's traditional exercise of grandfathering authority through rulemaking. The court observed that this approach was consistent with the statutory requirement to ''enforce whatever regulations are in effect at the time the agency makes a final decision'' because it involved identifying ''an operative date, incident to setting the new substantive standard, and the grandfathering of pending permit applications was explicitly built into the new regulations.'' *Sierra Club* v. *EPA,* 762 F.3d 971, 983 (9th Cir. 2014). As discussed in more detail in the EPA's Response to Comment Document contained in the docket for this rule, this case supports the EPA's action in this rulemaking. The court favorably discussed prior adoption of regulatory grandfathering provisions that are similar to the action in this rulemaking, such as the grandfathering provision that the EPA promulgated when revising the $PM_{2.5}$ NAAQS that became effective in 2013. *See id.* at 982–83.[227]

This adoption of a grandfathering provision in this action is also consistent with previous actions in which the EPA has recognized that the CAA provides discretion for the EPA to establish grandfathering provisions for PSD permit applications through regulations. Some examples of previous references to the EPA's authority to grandfather certain applications through rulemaking include 45 FR 52683, August 7, 1980; 52 FR 24672, July 1, 1987; and most recently 78 FR 3086, January 15, 2013.

This grandfathering provision does not apply to any applicable PSD requirements related to O_3 other than the requirement to demonstrate that the proposed source does not cause or contribute to a violation of the revised O_3 NAAQS. Sources with projects qualifying under the grandfathering provision will be required to meet all the other applicable PSD requirements, including applying BACT to all applicable pollutants, demonstrating that emissions from the proposed facility will not cause or contribute to a violation of the O_3 NAAQS in effect at the time of the relevant grandfathering milestone, and addressing any Class I area and additional O_3-related impacts in accordance with the applicable PSD requirements. In addition, this grandfathering provision would not apply to any permit application for a new or modified major stationary source of O_3 located in an area designated nonattainment for O_3 on the date the permit is issued.

VIII. Implementation of the Revised O_3 Standards

This section provides background information for understanding the implications of the revised O_3 NAAQS and describes the EPA's plans for providing revised rules or additional guidance on some subjects in a timely manner to assist states with their implementation efforts under the requirements of the CAA. This section also describes existing EPA rules, interpretations of CAA requirements, and other EPA guidance relevant to implementation of the revised O_3 NAAQS. Relevant CAA provisions that provide potential flexibility with regard to meeting implementation timelines are highlighted and discussed. This section also contains a discussion of how existing requirements to reduce the impact on O_3 concentrations from the stationary source construction in permit programs under the CAA are affected by the revisions to the O_3 NAAQS. These are the PSD and Nonattainment New Source Review (NNSR) programs. As discussed in section VII of this preamble, to facilitate a smooth transition to the PSD requirements for the revised O_3 NAAQS, the EPA is finalizing as part of this rulemaking a grandfathering provision that applies to certain PSD permit applications that are pending and have met certain milestones in the permitting process

[227] This case specifically involved an action by the EPA to issue an individual PSD permit, which grandfathered a specific permit applicant from certain requirements without any revision to the regulations that were in effect. The court's reasoning in this case distinguishes that type of permit-specific grandfathering from establishing grandfathering provisions through a rulemaking process. While the court was not persuaded that there was a conflict between the requirements of sections 165(a)(3) and 165(c) of the CAA that supported the permit-specific grandfathering at issue in that case, it did not extend that uncertainty to its discussion of the EPA's rulemaking authority. In fact, in its favorable discussion of the EPA's authority to grandfather pending permit applications through regulation, the court noted that the power of an administrative agency ''to administer a congressionally created and funded program necessarily requires the formulation of policy and the making of rules to fill any gap left, implicitly or explicitly, by Congress'' though ''such decision cannot be made on an ad hoc basis.'' *Sierra Club* v. *EPA,* 762 F.3d 971, 983 (9th Cir. 2014) (internal quotations and marks omitted). This indicates that the court believed there is a gap in the CAA that supports including grandfathering provisions in regulations.

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when the revised O_3 NAAQS is signed or before the effective date of the revised O_3 NAAQS, depending on the milestone.

In the preamble for the O_3 NAAQS proposal, the EPA solicited comments on several issues related to implementing the revised O_3 NAAQS that the agency anticipated addressing in future guidance or regulatory actions, but for which the EPA was not at that time proposing any action. The EPA received numerous comments on those and other implementation issues. Consistent with what the EPA indicated in the O_3 NAAQS proposal (79 FR 75370), the agency is not responding to the implementation comments that are not related to a specific proposal. However, the EPA intends to take these comments under advisement as the agency develops rules and guidance to assist with implementation of the revised NAAQS. Because the EPA did specifically propose and is finalizing provisions in the regulations addressing grandfathering for certain PSD permit applications and requirements, as discussed in section VII of this preamble, the EPA is responding to comments on the proposed PSD grandfathering provisions.

A. NAAQS Implementation Plans

1. Cooperative Federalism

As directed by the CAA, reducing pollution to meet national air quality standards always has been a shared task, one involving the federal government, states, tribes and local air quality management agencies. The EPA develops regulations and strategies to reduce pollution on a broad scale, while states and tribes are responsible for implementation planning and any additional emission reduction measures necessary to bring specific areas into attainment. The agency supports implementation planning with technical resources, guidance, and program rules where necessary, while air quality management agencies use their knowledge of local needs and opportunities in designing emission reduction strategies that will work best for their industries and communities.

This partnership has proved effective since the EPA first issued O_3 standards more than three decades ago. For example, 101 areas were designated as nonattainment for the 1-hour O_3 standards issued in 1979. As of the end of 2014, air quality in all but one of those areas meets the 1-hour standards. The EPA strengthened the O_3 standards in 1997, shifting to an 8-hour standard to improve public health protection, particularly for children, the elderly, and other sensitive individuals. The 1997 standards drew significant public attention when they were proposed, with numerous parties voicing concerns about states' ability to comply. However, after close collaboration between the EPA, states, tribes and local governments to reduce O_3-forming pollutants, significant progress has been made. Air quality in 108 of the original 115 areas designated as nonattainment for the 1997 O_3 NAAQS now meets those standards. Air quality in 18 of the original 46 areas designated as nonattainment for the 2008 O_3 NAAQS now meets those standards.

The revisions to the primary and secondary O_3 NAAQS discussed in sections II.D and IV.D of this preamble trigger a process under which states [228] make recommendations to the Administrator regarding area designations. Then, the EPA promulgates the final area designations. States also are required to review capacity and authorities in their existing SIPs to ensure the CAA requirements associated with the new standards can be carried out, and modify or supplement their existing SIPs as needed. The O_3 NAAQS revisions also apply to the transportation conformity and general conformity determinations, and affect which preconstruction permitting requirements apply to sources of O_3 precursor emissions, and the nature of those requirements.

The EPA has regulations in place addressing the general requirements for SIPs, and there are also provisions in these existing rules that cover O_3 SIPs (40 CFR part 51). States likewise have provisions in their existing SIPs to address air quality for O_3 and to implement the existing O_3 NAAQS. In the course of the past 45 years of regulating criteria pollutants, including O_3, the EPA has also provided general guidance on the development of SIPs and administration of construction permitting programs, as well as specific guidance on implementing the O_3 NAAQS in some contexts under the CAA and the EPA regulations.

The EPA has considered the extent to which existing EPA regulations and guidance are sufficient to implement the revised standards. The CAA does not require that the EPA promulgate new implementing regulations or issue new guidance for states every time that a NAAQS is revised. Likewise, the CAA does not require the issuance of additional implementing regulations or guidance by the EPA before a revised NAAQS becomes effective. It is important to note that the existing EPA regulations in 40 CFR part 51 applicable to SIPs generally and to particular pollutants, including O_3 and O_3 precursors, continue to apply unless and until they are updated. Accordingly, the discussion below provides the EPA's current thoughts about the extent to which revisions to existing regulations and additional guidance are appropriate to aid in the implementation of the revised O_3 NAAQS.

2. Additional New Rules and Guidance

The EPA has received comments from a variety of states and organizations asking for rules and guidance associated with a revised NAAQS to be issued in a timely manner. As explained above, and consistent with the proposal, the EPA is not responding to these comments at this time because they are not related to any changes to existing regulations that EPA proposed in this rule. Moreover, although issuance of such rules and guidance is not a part of the NAAQS review process, *National Ass'n of Manufacturers* v. *EPA,* 750 F. 3d 921, 926–27 (D.C. Cir. 2014), toward that end, the EPA intends to develop appropriate revisions to necessary implementation rules and provide additional guidance in time frames that are useful to states when developing implementation plans that meet CAA requirements.

Certain requirements under the PSD preconstruction permit review program apply immediately to a revised NAAQS upon the effective date of that NAAQS, unless the EPA has established a grandfathering provision through rulemaking. To ensure a smooth transition to a revised O_3 NAAQS, the EPA is finalizing a grandfathering provision similar to the provision finalized in the 2012 $PM_{2.5}$ NAAQS Rule. *See* section VII.C of this preamble for more details on the PSD program and the final grandfathering provision.

Promulgation or revision of the NAAQS starts a clock for the EPA to designate areas as either attainment or nonattainment. State recommendations for area designations are due to the EPA within 12 months of promulgating or revising the NAAQS. In an effort to allow states to make more informed recommendations for these particular standards, the EPA intends to issue additional guidance concerning the designations process for these standards within four months of promulgation of the NAAQS, or approximately eight months before state recommendations are due. The EPA generally completes

[228] This and all subsequent references to "state" are meant to include state, local, and tribal agencies responsible for the implementation of an O_3 control program.

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area designations two years after promulgation of a NAAQS. *See* section VIII.B of this preamble for additional information on the initial area designation process.

Under CAA section 110, a NAAQS revision triggers the review and, as necessary, revision of SIPs to be submitted within three years of promulgation of a revised NAAQS. These SIPs are referred to as ''infrastructure SIPs.'' The EPA issued general guidance on submitting infrastructure SIPs on September 13, 2013.[229] It should be noted that this guidance did not address certain state planning and emissions control requirements related to interstate pollution transport. This guidance remains relevant for the revised O_3 NAAQS. *See* section VIII.A.4 of this preamble for additional information on infrastructure SIPs.

While much of the existing rules and guidance for prior ozone standards remains applicable to the new standards, the EPA intends to propose to adopt revised rules on some subjects to facilitate air agencies' efforts to implement the revised O_3 NAAQS within one year after the revised NAAQS is established. The rules would address nonattainment area classification methodologies and attainment dates, attainment plan and NNSR SIP submission due dates, and any other necessary revisions to existing regulations for other required implementation programs. The EPA anticipates finalizing these rules by the time areas are designated nonattainment. Finalizing rules and guidance on these subjects by this time would assist air quality management agencies with development of any CAA-required SIPs associated with nonattainment areas. *See* section VIII.A.5 of this preamble for additional information on nonattainment SIPs and section VIII.C.3 for additional information on nonattainment New Source Review requirements applicable to new major sources and major modifications of existing sources.

3. Background O_3

The EPA and state, local and tribal air agencies, strive to determine how to most effectively and efficiently use the CAA's various provisions to provide required public health and welfare protection from the harmful effects of O_3. In most cases, reducing man-made emissions of NO_X and VOCs within the U.S. will reduce O_3 formation and provide additional health and welfare protection. The EPA recognizes, however, that there can be infrequent events where daily maximum 8-hour O_3 concentrations approach or exceed 70 ppb largely due to the influence of wildfires or stratospheric intrusions, which contribute to U.S. background (USB) levels but may also qualify for consideration under the Exceptional Events Rule. See section I.D; but see section II.A.2.a above (percentage of anthropogenic O_3 tends to increase on high O_3 days relative to percentage of background, including in intermountain west).

The term ''background'' O_3 is often used to refer to O_3 that originates from natural sources of O_3 (*e.g.,* wildfires and stratospheric O_3 intrusions) and O_3 precursors, as well as from man-made international emissions of O_3 precursors. Using the term generically, however, can lead to confusion as to what sources of O_3 are being considered. Relevant to the O_3 implementation provisions of the CAA, we define background O_3 the same way the EPA defines USB: O_3 that would exist in the absence of any man-made emissions inside the U.S.

While the great majority of modeled O_3 exceedances have local and regional emissions as their primary cause, there can be events where O_3 levels approach or exceed the concentration level of the revised O_3 standards in large part due to background sources. These cases of high USB levels on high O_3 days typically result from stratospheric intrusions of O_3 or wildfire O_3 plumes. These events are infrequent and the CAA contains provisions that can be used to help deal, in particular, with stratospheric intrusion and wildfire events with O_3 contributions of this magnitude, including providing varying degrees of regulatory relief for air agencies and potential regulated entities. The EPA intends to work closely with states to identify affected locations and ensure that the appropriate regulatory mechanisms are employed.

Statutory and regulatory relief associated with U.S. background O_3 may include: [230]

- Relief from designation as a nonattainment area through exclusion of data affected by exceptional events;
- Relief from the more stringent requirements of higher nonattainment area classifications through treatment as a rural transport area, through exclusion of data affected by exceptional events, or through international transport provisions;
- Relief from having to demonstrate attainment and having to adopt more than reasonable controls on local sources through international transport provisions.

Further discussion of these mechanisms is provided in sections VIII.B.2 (exceptional events), VIII.B.1 (rural transport areas), and VIII.E.2 (international transport).

Although these relief mechanisms require some level of assessment or demonstration by a state and/or the EPA to invoke, they have been used successfully in the past under appropriate circumstances. For example, the EPA has historically acted on every exceptional events demonstration that has affected a regulatory decision regarding initial area designations. *See e.g., Idaho: West Silver Valley Nonattainment Area—Area Designations for the 2012 primary annual $PM_{2.5}$* NAAQS Technical Support Document, pp. 10–14, December 2014. For the revised O_3 standards, the areas that would most likely need to use the mechanisms discussed in this section as part of attaining the revised O_3 standards are locations in the western U.S. where we have estimated the largest seasonal average values of background O_3 occur. We expect some of these areas to use the provisions in the Exceptional Events Rule during the designations process for the revised O_3 standards. The EPA will then give priority to exceptional events demonstrations submitted by air agencies with areas whose designation decision could be influenced by the exclusion of data under the Exceptional Events Rule. In addition, as discussed in more detail in sections V.D and VIII.B.2 of this action, to streamline the exceptional events process, the EPA will soon propose revisions to the 2007 Exceptional Events Rule and will release through a **Federal Register** Notice of Availability a draft guidance document to address Exceptional Events Rule criteria for wildfires that could affect O_3 concentrations. We expect to

[229] *See* memorandum from Stephen D. Page to Regional Air Directors, ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)'' September 13, 2013, which is available at *http://www3.epa.gov/airquality/urbanair/sipstatus/docs/Guidance_on_Infrastructure_SIP_Elements_Multipollutant_FINAL_Sept_2013.pdf.*

[230] Note that the relief mechanisms discussed here do not include the CAA's interstate transport provisions found in sections 110(a)(2)(D) and 126. The interstate transport provisions are intended to address the cross-state transport of O_3 and O_3 precursor emissions from man-made sources within the continental U.S. rather than background O_3 as it is defined in this section. As noted in section II.A.2.a above, many of the instances where commenters pointed to remote monitored locations having O_3 exceedances due to background O_3 in fact reflected sizeable contributions from domestic sources, including interstate contributions (including from the Los Angeles Basin and other California locations).

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promulgate Exceptional Events Rule revisions and finalize the new guidance document before the October 2016 date by which states, and any tribes that wish to do so, are required to submit their initial designation recommendations for the revised O_3 NAAQS.

4. Section 110 State Implementation Plans

The CAA section 110 specifies the general requirements for SIPs. Within three years after the promulgation of revised NAAQS (or such shorter period as the Administrator may prescribe [231]) each state must adopt and submit ''infrastructure'' SIPs to the EPA to address the requirements of section 110(a)(1) and (2), as applicable. These ''infrastructure SIP'' submissions establish the basic state programs to implement, maintain, and enforce revised NAAQS and provide assurances of state resources and authorities. States are required to develop and maintain an air quality management infrastructure that includes enforceable emission limitations, a permitting program, an ambient monitoring program, an enforcement program, air quality modeling capabilities, and adequate personnel, resources, and legal authority. Because the revised primary NAAQS and secondary NAAQS are identical, the EPA does not at present discern any need for there to be any significant substantive difference in the infrastructure SIP elements for the two standards and thus believes it would be more efficient for states and the EPA if each affected state submits a single section 110 infrastructure SIP that addresses both standards at the same time (*i.e.,* within three years of promulgation of the O_3 NAAQS). Accordingly the EPA is not extending the SIP deadline for purposes of a revised secondary standard.

It is the responsibility of each state to review its air quality management program's compliance with the infrastructure SIP provisions in light of each new or revised NAAQS. Most states have revised and updated their infrastructure SIPs in recent years to address requirements associated with the 2008 O_3 NAAQS. We expect that the result of these prior updates is that, in most cases, states will already have adequate state regulations previously adopted and approved into the SIP to address a particular requirement with respect to the revised O_3 NAAQS. For such portions of the state's infrastructure SIP submission, the state may provide a ''certification'' specifying that certain existing provisions in the SIP are adequate to meet applicable requirements. Although the term ''certification'' does not appear in the CAA as a type of infrastructure SIP submittal, the EPA sometimes uses the term in the context of infrastructure SIPs, by policy and convention, to refer to a state's SIP submission. If a state determines that its existing EPA-approved SIP provisions are adequate in light of the revised O_3 NAAQS with respect to a given infrastructure SIP element (or sub-element), then the state may make a ''certification'' that the existing SIP contains provisions that address those requirements of the specific CAA section 110(a)(2) infrastructure elements. In the case of a certification, the submittal does not have to include another copy of the relevant provision (*e.g.,* rule or statute) itself. Rather, the submission may provide citations to the already SIP-approved state statutes, regulations, or non-regulatory measures, as appropriate, which meet the relevant CAA requirement. Like any other SIP submission, such certification can be made only after the state has provided reasonable notice and opportunity for public hearing. This ''reasonable notice and opportunity for public hearing'' requirement for infrastructure SIP submittals appears at section 110(a), and it comports with the more general SIP requirement at section 110(l) of the CAA. Under the EPA's regulations at 40 CFR part 51, if a public hearing is held, an infrastructure SIP submission must include documentation by the state that the public hearing was held in accordance with the EPA's procedural requirements for public hearings. See 40 CFR part 51, Appendix V, paragraph 2.1(g), and 40 CFR 51.102. In the event that a state's existing SIP does not already meet applicable requirements, then the infrastructure SIP submission must include the modifications or additions to the state's SIP in order to update it to meet the relevant elements of section 110(a)(2).

5. Nonattainment Area Requirements

Part D of the CAA describes the various program requirements that apply to states with nonattainment areas for different NAAQS. Clean Air Act Section 182 (found in subpart 2 of part D) includes the specific SIP requirements that govern the O_3 program, and supplements the more general nonattainment area requirements in CAA sections 172 and 173. Under CAA section 182, states generally are required to submit attainment demonstration SIPs within three or four years after the effective date of area designations promulgated by the EPA, depending on the classification of the area.[232] These SIP submissions need to show how the nonattainment area will attain the primary O_3 standard ''as expeditiously as practicable,'' but no later than within the relevant time frame from the effective date of designations associated with the classification of the area.

The EPA believes that the overall framework and policy approach of the implementation rules associated with the 2008 O_3 NAAQS provide an effective and appropriate template for the general approach states would follow in planning for attainment of the revised O_3 standard.[233] However, to assist with the implementation of the revised O_3 standards, the EPA intends to develop and propose an additional O_3 NAAQS Implementation Rule that will address certain subjects specific to the new O_3 NAAQS finalized here. This will include establishing air quality thresholds associated with each nonattainment area classification (*i.e.,* Marginal, Moderate, etc.), associated attainment deadlines, and deadlines for submitting attainment planning SIP elements (*e.g.,* RACT for major sources, RACT VOC control techniques guidelines, etc.). The rulemaking will also address whether to revoke the 2008 O_3 NAAQS, and to impose appropriate anti-backsliding requirements to ensure that the protections afforded by that standard are preserved. The EPA intends to propose this implementation rule within one year after the revised O_3 NAAQS is promulgated, and finalize this implementation rule by no later than the time the area designations process is finalized (approximately two years after promulgation of the revised O_3 NAAQS).

We know that developing the implementation plans that outline the steps a nonattainment area will take to

[231] While the CAA allows the EPA to set a shorter time for submission of these SIPs, the EPA does not currently intend to do so for this revision to the O_3 NAAQS.

[232] Section 181(a)(1) of the CAA establishes classification categories for areas designated nonattainment for the primary O_3 NAAQS. These categories range from ''Marginal,'' the lowest O_3 classification with the fewest requirements associated with it, to ''Extreme,'' the highest classification with the most required programs. Areas with worse O_3 problems are given more time to attain the NAAQS and more associated emission control requirements.

[233] Implementation of the 2008 National Ambient Air Quality Standards for Ozone: State Implementation Plan Requirements; Final Rule (80 FR 12264; March 6, 2015) and Implementation of the 2008 National Ambient Air Quality Standards for Ozone: Nonattainment Area Classifications Approach, Attainment Deadlines and Revocation of the 1997 Ozone Standards for Transportation Conformity Purposes (77 FR 30160; May 21, 2012).

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meet an air quality standard requires a significant amount of work on the part of state, tribal or local air agencies. The EPA routinely looks for ways to reduce this workload, including assisting with air quality modeling by providing inputs such as emissions, meteorological and boundary conditions; and sharing national-scale model results that states can leverage in their development of attainment demonstrations.

B. O_3 Air Quality Designations

1. Area Designation Process

After the EPA establishes or revises a NAAQS, the CAA directs the EPA and the states to take steps to ensure that the new or revised NAAQS is met. One of the first steps, known as the initial area designations, involves identifying areas of the country that either meet or do not meet the new or revised NAAQS, along with any nearby areas that contribute to areas that do not meet the new or revised NAAQS.

Section 107(d)(1) of the CAA provides that, ''By such date as the Administrator may reasonably require, but not later than 1 year after promulgation of a new or revised national ambient air quality standard for any pollutant under section 109, the Governor of each state shall . . . submit to the Administrator a list of all areas (or portions thereof) in the state'' that designates those areas as nonattainment, attainment, or unclassifiable. The EPA must then promulgate the area designations according to a specified process, including procedures to be followed if the EPA intends to modify a state's initial recommendation.

Clean Air Act Section 107(d)(1)(B)(i) further provides, ''Upon promulgation or revision of a national ambient air quality standard, the Administrator shall promulgate the designations of all areas (or portions thereof) . . . as expeditiously as practicable, but in no case later than 2 years from the date of promulgation of the new or revised national ambient air quality standard. Such period may be extended for up to one year in the event the Administrator has insufficient information to promulgate the designations.'' By no later than 120 days prior to promulgating area designations, the EPA is required to notify states of any intended modifications to their recommendations that the EPA may deem necessary. States then have an opportunity to demonstrate why any proposed modification is inappropriate. Whether or not a state provides a recommendation, the EPA must timely promulgate the designation that the agency deems appropriate.

While section 107 of the CAA specifically addresses states, the EPA intends to follow the same process for tribes to the extent practicable, pursuant to CAA section 301(d) regarding tribal authority and the Tribal Authority Rule (63 FR 7254, February 12, 1998). To provide clarity and consistency in doing so, the EPA issued a 2011 guidance memorandum on working with tribes during the designation process.[234]

As discussed in sections II and IV of this preamble, the EPA is revising both the primary and secondary O_3 NAAQS. Accordingly, the EPA intends to complete designations for both NAAQS following the standard 2-year process discussed above. In accordance with section 107(d)(1) of the CAA, state Governors (and tribes, if they choose) should submit their initial designation recommendations for a revised primary and secondary NAAQS by 1 year after October 1, 2015. If the EPA intends to modify any state recommendation, the EPA would notify the appropriate state Governor (or tribal leader) no later than 120 days prior to making final designation decisions. A state or tribe that believes the modification is inappropriate would then have the opportunity to demonstrate to the EPA why it believes its original recommendation (or a revised recommendation) is more appropriate. The EPA would take any additional input into account in making the final designation decisions.

The CAA defines an area as nonattainment if it is violating the NAAQS or if it is contributing to a violation in a nearby area. Consistent with previous area designations processes, the EPA intends to use area-specific analysis of multiple factors to support area boundary decisions. The EPA intends to evaluate information related to the following factors for designations: air quality data, emissions and emissions-related data, meteorology, geography/topography, and jurisdictional boundaries. Additional guidance on the designation process and how these factors may be evaluated and inform the process will be issued by the EPA early in 2016 to assist states in developing their recommendations.

[234] Page, S. (2011). Guidance to Regions for Working with Tribes during the National Ambient Air Quality Standards (NAAQS) Designations Process, Memorandum from Stephen D. Page, Director, EPA Office of Air Quality Planning and Standards to Regional Air Directors, Regions I–X, December 20, 2011. Available: *http://www.epa.gov/ttn/oarpg/t1/memoranda/20120117naaqsguidance.pdf.*

Areas that are designated as nonattainment are also classified at the time of designation by operation of law according to the severity of their O_3 problem. The classification categories are Marginal, Moderate, Serious, Severe, and Extreme. Ozone nonattainment areas are subject to specific mandatory measures depending on their classification. As indicated previously, the thresholds for the classification categories will be established in a future O_3 implementation rule.

Clean Air Act section 182(h) authorizes the EPA Administrator to determine that an area designated nonattainment can be treated as a rural transport area. Regardless of its classification, a rural transport area is deemed to have fulfilled all O_3-related planning and control requirements if it meets the CAA's requirements for areas classified Marginal, which is the lowest classification specified in the CAA. In accordance with the statute, a nonattainment area may qualify for this determination if it meets the following criteria:

- The area does not contain emissions sources that make a significant contribution to monitored O_3 concentrations in the area, or in other areas; and
- The area does not include and is not adjacent to a Metropolitan Statistical Area.

Historically, the EPA has listed four nonattainment areas as rural transport areas under this statutory provision.[235] The EPA has not issued separate written guidance to further elaborate on the interpretation of these CAA qualification criteria. However, the EPA developed draft guidance in 2005 that explains the kinds of technical analyses that states could use to establish that transport of O_3 and/or O_3 precursors into the area is so overwhelming that the contribution of local emissions to an observed 8-hour O_3 concentration above the level of the NAAQS is relatively minor and determine that emissions within the area do not make a significant contribution to the O_3 concentrations measured in the area or in other areas.[236] While this guidance

[235] For the 1979 1-hour O_3 standard, Door County Area, Wisconsin; Edmonson County Area, Kentucky; Essex County Area (Whiteface Mountain), New York; and Smyth County Area (White Top Mountain), Virginia were recognized by the EPA as rural transport areas. No rural transport areas were recognized for the 1997 or 2008 8-hour O_3 standards.

[236] U.S. Environmental Protection Agency (2005). Criteria For Assessing Whether an Ozone Nonattainment Area is Affected by Overwhelming Transport [Draft EPA Guidance]. U.S. Environmental Protection Agency, Research Triangle Park, NC. June 2005. Available at *http://*

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was not prepared specifically for rural transport areas, it could be useful to states for developing technical information to support a request that the EPA treat a specific O_3 nonattainment area as a rural transport area. The EPA will work with states to ensure nonattainment areas eligible for treatment as rural transport areas are identified.

2. Exceptional Events

During the initial area designations process, the EPA intends to evaluate multiple factors, including air quality data, when identifying and determining boundaries for areas of the country that meet or do not meet the revised O_3 NAAQS. In some cases, these data may be influenced by exceptional events. Under the Exceptional Events Rule, an air agency can request and the EPA can agree to exclude data associated with event-influenced exceedances or violations of a NAAQS, including the revised O_3 NAAQS, provided the event meets the statutory requirements in section 319(b) of the CAA, which requires that:

- the event ''affects air quality;''
- the event ''is not reasonably controllable or preventable;''
- the event is ''caused by human activity that is unlikely to recur at a particular location or [is] a natural event,'' [237] and
- that ''a clear causal relationship must exist between the measured exceedances of a [NAAQS] and the exceptional event............''

The EPA's implementing regulations, the Exceptional Events Rule, further specify certain requirements for air agencies making exceptional events demonstrations.[238]

The ISA contains discussions of natural events that may contribute to O_3 or O_3 precursors. These include stratospheric O_3 intrusion and wildfire events.[239] As indicated above, to satisfy the exceptional events requirements and to qualify for data exclusion under the Exceptional Events Rule, an air agency must develop and submit a demonstration, including evidence, addressing each of the identified criteria. The extent to which a stratospheric O_3 intrusion event or a wildfire event contributes to O_3 levels can be uncertain, and in most cases requires detailed analyses to determine.

Strong stratospheric O_3 intrusion events, most prevalent at high elevation sites during winter or spring, can be identified based on measurements of low relative humidity, evidence of deep atmospheric mixing, and a low ratio of CO to O_3 based on ambient measurements. Accurately determining the extent of weaker intrusion events remains challenging (U.S. EPA 2013, p. 3–34). Although states have submitted only a few exceptional events demonstrations for stratospheric O_3 intrusion, the EPA recently approved a demonstration from Wyoming for a June 2012 stratospheric O_3 event.[240]

While stratospheric O_3 intrusions can increase monitored ground-level ambient O_3 concentrations, wildfire plumes can either suppress or enhance O_3 depending upon a variety of factors including fuel type, combustion stage, plume chemistry, aerosol effects, meteorological conditions and distance from the fire (Jaffe and Wigder, 2012). As a result, determining the impact of wildfire emissions on specific O_3 observations is challenging. The EPA recently approved an exceptional events demonstration for wildfires affecting 1-hour O_3 levels in Sacramento, California in 2008 that successfully used a variety of analytical tools (*e.g.,* regression modeling, back trajectories, satellite imagery, etc.) to support the exclusion of O_3 data affected by large fires.[241]

In response to previously expressed stakeholder feedback regarding implementation of the Exceptional Events Rule and specific stakeholder concerns regarding the burden of exceptional events demonstrations, the EPA is currently engaged in a rulemaking process to amend the Exceptional Events Rule. As part of an upcoming notice and comment rulemaking effort (and related activities, including the issuance of relevant guidance documents), the EPA sees opportunities to standardize best practices for collaboration between the EPA and air agencies, clarify and simplify demonstrations, and improve tools and consistency.

Additionally, the EPA intends to develop guidance to address implementing the Exceptional Events Rule criteria for wildfires that could affect ambient O_3 concentrations. Wildfire emissions are a component of background O_3 (Jaffe and Wigder, 2012) and in some locations can significantly contribute to periodic high O_3 levels (Emery, 2012). The threat from wildfires can be mitigated through management of wildland vegetation. Planned and managed fires are one tool that land managers can use to reduce fuel load, unnatural understory and tree density, thus helping to reduce the risk of catastrophic wildfires. Allowing some wildfires to continue and the thoughtful use of prescribed fire can influence the occurrence of catastrophic wildfires, which may reduce the probability of fire-induced smoke impacts and subsequent health effects. Thus, appropriate use of prescribed fire may help manage the contribution of wildfires to both background and periodic peak O_3 air pollution. Several commenters expressed concern that the revised O_3 NAAQS could limit the future use of prescribed fire. Under the current Exceptional Events Rule, prescribed fires meeting the rule criteria may also qualify as exceptional events. The EPA intends to further clarify the Exceptional Events Rule criteria for prescribed fire on wildland in its upcoming rulemaking.

The EPA is committed to working with federal land managers, other federal agencies, tribes and states to effectively manage prescribed fire use to reduce the impact of wildfire-related emissions on O_3 through policies and regulations implementing these standards.

C. How do the New Source Review (NSR) requirements apply to the revised O_3 NAAQS?

1. NSR Requirements for Major Stationary Sources for the Revised O_3 NAAQS

The CAA, at parts C and D of title I, contains preconstruction review and permitting programs applicable to new major stationary sources and major modifications of existing major sources. The preconstruction review of each new major stationary source and major modification applies on a pollutant-specific basis, and the requirements that apply for each pollutant depend on whether the area in which the source is situated is designated as attainment (or

www.epa.gov/scram001/guidance/guide/owt_guidance_07-13-05.pdf.

[237] A natural event is further described in 40 CFR 50.1(k) as ''an event in which human activity plays little or no direct causal role.''

[238] 72 *FR 13,560* (March 22, 2007), ''Treatment of Data Influenced by Exceptional Events,'' Final Rule; *see also* 40 CFR parts 50 and 51.

[239] The preamble to the Exceptional Events Rule (72 FR 13560) identifies both stratospheric O_3 intrusions and wildfires as natural events that could also qualify as exceptional events under the CAA and Exceptional Event Rule criteria. Note that O_3 resulting from routine natural emissions from vegetation, microbes, animals and lightning are not exceptional events authorized for exclusion under the section 319 of the CAA.

[240] U.S. EPA (2014) Treatment of Data Influenced by Exceptional Events: Examples of Reviewed Exceptional Event Submissions. U.S. Environmental Protection Agency, Research Triangle Park, NC, *available at http://www.epa.gov/ttn/analysis/exevents.htm.*

[241] U.S. EPA (2014) Treatment of Data Influenced by Exceptional Events: Examples of Reviewed Exceptional Event Submissions. U.S. Environmental Protection Agency, Research Triangle Park, NC. Examples of O_3-related exceptional event submissions, *available at http://www.epa.gov/ttn/analysis/exevents.htm.*

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unclassifiable) or nonattainment for that pollutant. In areas designated attainment or unclassifiable for a pollutant, the PSD requirements under part C apply to construction at major sources. In areas designated nonattainment for a pollutant, the NNSR requirements under part D apply to major source construction. Collectively, those two sets of permit requirements are commonly referred to as the ''major New Source Review'' or ''major NSR'' programs.

Until an area is formally designated with respect to the revised O_3 NAAQS, the NSR provisions applicable under that area's current designation for the 2008 O_3 NAAQS (including any applicable anti-backsliding requirements) will continue to apply. That is, for areas designated as attainment/unclassifiable for the 2008 O_3 NAAQS, PSD will apply for new major stationary sources and major modifications that trigger major source permitting requirements for O_3; areas designated nonattainment for the 2008 O_3 NAAQS must comply with the NNSR requirements for new major stationary sources and major modifications that trigger major source permitting requirements for O_3. When the new designations for the revised O_3 NAAQS become effective, under the current rules, those designations will generally serve to determine whether PSD or NNSR applies to O_3 and its precursors. The PSD regulations at 40 CFR 51.166(i)(2) and 52.21(i)(2) provide that the substantive PSD requirements do not apply for a particular pollutant if the owner or operator of the new major stationary source or major modification demonstrates that the area in which the source is located is designated nonattainment for that pollutant under CAA section 107. Thus, new major sources and modifications will generally be subject to the PSD program requirements for O_3 if they are locating in an area that does not have a current nonattainment designation under CAA section 107 for O_3. These rules further provide that nonattainment designations for a revoked NAAQS, as contained in 40 CFR part 81, are not viewed as current designations under CAA section 107 for purposes of determining the applicability of such PSD requirements.[242]

The EPA's major NSR regulations define the term ''regulated NSR pollutant'' to include any pollutant for which a NAAQS has been promulgated and any pollutant identified in EPA regulations as a constituent or precursor to such pollutant.[243] Both the PSD and NNSR regulations identify VOC and NO_X as precursors to O_3. Accordingly, the major NSR programs for O_3 are applied to emissions of VOC and NO_X as precursors of O_3.[244]

2. Prevention of Significant Deterioration (PSD) Program

The statutory requirements for a PSD permit program set forth under part C of title I of the CAA (sections 160 through 169) are addressed by the EPA's PSD regulations found at 40 CFR 51.166 (minimum requirements for an approvable PSD SIP) and 40 CFR 52.21 (PSD permitting program for permits issued under the EPA's federal permitting authority). Both sets of regulations already apply for O_3 when the area is designated attainment or unclassifiable for O_3 and when the new source or modification triggers PSD requirements for O_3.

For PSD, a ''major stationary source'' is one that emits or has the potential to emit 250 tons per year (tpy) or more of any regulated NSR pollutant, unless the new or modified source is classified under a list of 28 source categories contained in the statutory definition of ''major emitting facility'' in section 169(1) of the CAA. For those 28 source categories, a ''major stationary source'' is one that emits or has the potential to emit 100 tpy or more of any regulated NSR pollutant. A ''major modification'' is a physical change or a change in the method of operation of an existing major stationary source that results first, in a significant emissions increase of a regulated NSR pollutant for the project, and second, in a significant net emissions increase of that pollutant at the source. *See* 40 CFR 51.166(b)(2)(i), 40 CFR 52.21(b)(2)(i).

Among other things, for each regulated NSR pollutant emitted or increased in significant amounts, the PSD program requires a new major stationary source or a major modification to apply Best Available Control Technology and to conduct an air quality impact analysis to demonstrate that the proposed source or project will not cause or contribute to a violation of any NAAQS or PSD increment (*see* CAA section 165(a)(3)–(4), 40 CFR 51.166(j)–(k), 40 CFR 52.21(j)–(k)). The PSD requirements may also include, in appropriate cases, an analysis of potential adverse impacts on Class I areas (*see* CAA sections 162 and 165).[245] The EPA has generally interpreted the requirement for an air quality impact analysis under CAA section 165(a)(3) and the implementing regulations to include a requirement to demonstrate that emissions from the proposed facility will not cause or contribute to a violation of any NAAQS that is in effect as of the date a PSD permit is issued.[246] *See, e.g.,* 73 FR 28321, 28324, 28340 (May 16, 2008); 78 FR 3253 (Jan. 15, 2013); Memorandum from Stephen D. Page, Director, Office of Air Quality Planning & Standards, ''Applicability of the Federal Prevention of Significant Deterioration Permit Requirements to New and Revised National Ambient Air Quality Standards'' (April 1, 2010). Consistent with this interpretation, the demonstration required under CAA section 165(a)(3) and 40 CFR 51.166(k) and 52.21(k) will apply to any revised O_3 NAAQS when such NAAQS become effective, except to the extent that a pending permit application is subject to a grandfathering provision that the EPA establishes through rulemaking. In addition, the other existing requirements of the PSD program will remain applicable to O_3 after the revised O_3 NAAQS takes effect.

Because the complex chemistry of O_3 formation in the atmosphere poses significant challenges for the assessing the impacts of individual stationary sources on O_3 formation, the EPA's judgment historically has been that it is not technically sound to designate a

[242] This description of paragraph (i)(2) of the PSD regulations at 40 CFR 51.166 and 52.21 reflects revisions made in the final 2008 O_3 NAAQS SIP Requirements Rule. *See* 80 FR 12264 at 12287 (March 6, 2015).

[243] The definition of ''regulated NSR pollutant'' is found in the PSD regulations at 40 CFR 51.166(b)(49) and 52.21(b)(50), and in the NNSR regulations at 40 CFR 51.165(a)(1)(xxxvii).

[244] VOC and NO_X are defined as precursors of ozone in the PSD regulations at 40 CFR 51.166(b)(49)(i)(b)(1) and 52.21(b)(50)(i)(b)(1), and in the NNSR regulations at 40 CFR 51.165(a)(1)(xxxvii)(B) and (C)(1) and part 51, Appendix S, II.A.31(ii)(b)(1).

[245] Congress established certain Class I areas in section 162(a) of the CAA, including international parks, national wilderness areas, and national parks that meet certain criteria. Such Class I areas, known as mandatory federal Class I areas, are afforded special protection under the CAA. In addition, states and tribal governments may establish Class I areas within their own political jurisdictions to provide similar special air quality protection.

[246] An exception occurs in cases where the EPA has included a grandfathering provision in its PSD regulations for a particular pollutant. The EPA historically has exercised its discretion to transition the implementation of certain new requirements through grandfathering, under appropriate circumstances, either by rulemaking or through a case-by-case determination for a specific permit application. In 2014, the United States Court of Appeals for the Ninth Circuit vacated a decision by the EPA to issue an individual PSD permit grandfathering a permit applicant from certain requirements. *See Sierra Club* v. *EPA,* 762 F.3d 971 (9th Cir. 2014). In light of that decision, the EPA is no longer asserting authority to grandfather permit applications on a case-by-case basis. This decision is addressed in more detail in the discussion of the grandfathering provisions that the EPA is issuing through this rulemaking in section VII of this preamble.

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specific air quality model that must be used in the PSD permitting process to make this demonstration for O_3. To address ambient impacts of emissions from proposed individual stationary sources on O_3, the EPA proposed amendments to Appendix W to 40 CFR part 51 in July 2015 that would, among other things, revise the Appendix W provisions relating to the analytical techniques for demonstrating that an individual PSD source or modification does not cause or contribute to a violation of the O_3 NAAQS (80 FR 45340, July 29, 2015). Until any revisions are finalized and in effect, PSD permit applicants should continue to follow the current provisions in the applicable regulations and Appendix W in order to demonstrate that a proposed source or modification does not cause or contribute to a violation of the O_3 NAAQS.

a. What transition plan is the EPA providing for implementing the PSD requirements for the revised O_3 NAAQS?

In this rulemaking, the EPA is amending the PSD regulations at 40 CFR 51.166 and 40 CFR 52.21 to include a grandfathering provision that will allow reviewing authorities to continue to review certain pending PSD permit applications in accordance with the O_3 NAAQS that was in effect when a specific permitting milestone was reached, rather than the revised O_3 NAAQS. The EPA is finalizing the grandfathering provision as proposed with two trigger dates—the signature date of the revised O_3 NAAQS rule for complete applications and the effective date of the revised O_3 NAAQS for a draft permit or preliminary determination. A more detailed discussion of the final provision, comments received and our responses to those comments is provided in section VII of this preamble, which addresses this change to the PSD regulations, as well as the Response to Comment Document contained in the docket for this rulemaking.

b. What screening and compliance demonstration tools are used to implement the PSD program?

The EPA has historically allowed the use of screening and compliance demonstration tools to help facilitate the implementation of the NSR program by reducing the source's burden and streamlining the permitting process for circumstances where the emissions or ambient impacts of a particular pollutant could be considered *de minimis.* For example, the EPA has established significant emission rates, or SERs, that are used as screening tools to determine when a pollutant would be considered to be emitted in a significant amount and, accordingly, when the NSR requirements should be applied to that pollutant. *See* 40 CFR 51.166(b)(23) and 52.21(b)(23). For O_3, the EPA established a SER of 40 tpy for emissions of each O_3 precursor—VOC and NO_X. For PSD, the O_3 SER applies independently to emissions of VOC and NO_X (emissions of precursors are not added together) to determine when the proposed major stationary source or major modification must undergo PSD review for that precursor and whether individual PSD requirements, such as BACT, apply to that precursor.[247]

In the context of the PSD air quality impact analysis, the EPA has also used a value called a significant impact level (SIL) as a compliance demonstration tool. The SIL, expressed as an ambient concentration of a pollutant, may be used first to determine the geographical scope of the ambient impact analysis that must be completed for the applicable pollutant to satisfy the air quality demonstration requirement under CAA section 165(a)(3). A second use is to guide the determination of whether the impact of the source is considered to cause or contribute to a violation of any NAAQS. The EPA has not established a SIL for O_3. The EPA is currently considering development of a SIL for O_3 through either guidance or a rulemaking process. Such a SIL would complement proposed revisions to Appendix W mentioned above (80 FR 45340, July 29, 2015) and would assist in the implementation of the PSD air quality analysis requirement for protection of the O_3 NAAQS. However, the EPA is not making revisions in this rulemaking to address the PSD air quality analysis for O_3. Until any rulemaking to amend existing PSD regulations for O_3 is completed, permitting decisions should continue to be based on the existing provisions in the applicable regulations.

Several commenters addressed statements that the EPA made concerning screening tools for O_3 in the preamble to the O_3 NAAQS proposal. These statements were not linked to any proposed amendments to EPA regulations. Aside from adopting the grandfathering provision addressed in section VII of this preamble, the EPA is not revising the PSD requirements for O_3 in this final rule. Therefore, the EPA is not responding to those comments at this time, consistent with the EPA's general approach to comments on implementation topics described above.

c. Other PSD Transition Issues

The EPA anticipates that the existing O_3 air quality in some areas currently designated attainment of unclassifiable for O_3 will not meet the revised O_3 NAAQS upon its effective date and that some of these areas will ultimately be designated ''nonattainment'' for the revised O_3 NAAQS through the formal area designation process set forth under the CAA (see section VIII.B above). However, until the EPA issues such nonattainment designations, proposed new major sources and major modifications situated in any area designated attainment or unclassifiable for the 2008 O_3 NAAQS will continue to be required to address O_3 in a PSD permit.[248] As mentioned above, the PSD permitting program requires that proposed new major stationary sources and major modifications must demonstrate that the emissions from the proposed source or modification will not cause or contribute to a violation of any NAAQS. In the notice of proposed rulemaking, the EPA provided information concerning its views on the possibility that some PSD permit applications could satisfy the air quality analysis requirements for O_3 by obtaining air quality offsets (called PSD offsets).[249] Several commenters expressed concern that without some transition provisions in the final rule exempting PSD permit applications for sources located in such areas from meeting the air quality analysis requirements for the revised O_3 NAAQS, such applications might not be able to satisfy the demonstration requirement, as the current ambient air monitoring data indicate the revised lower standards are not being met. The O_3 NAAQS proposal included no proposed revisions to PSD regulations on this

[247] *See In re Footprint Power Salem Harbor Development, LP,* 16 E.A.D., PSD Appeal No. 14–02, at 20–25 (EAB, Sept. 2, 2014) (including description of EPA's position on application of BACT to ozone precursors) *available at http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD+Permit+Appeals+(CAA)?OpenView.*

[248] Any proposed major stationary source or major modification subject to PSD for O_3 that does not receive its PSD permit by the effective date of a new O_3 nonattainment designation for the area where the source would locate would then be required to satisfy all of the applicable NNSR preconstruction permit requirements for O_3, even if such source had been grandfathered under the PSD regulations from the demonstration requirement under CAA section 165(a)(3) for O_3.

[249] The EPA has historically recognized in regulations and through other actions that sources applying for PSD permits may have the option of utilizing offsets as part of the required PSD demonstration under CAA section 165(a)(3)(B). *See, e.g., In re Interpower of New York, Inc.,* 5 E.A.D. 130, 141 (EAB 1994) (describing an EPA Region 2 PSD permit that relied in part on offsets to demonstrate the source would not cause or contribute to a violation of the NAAQS). 52 FR 24698 (July 1, 1987); 78 FR 3261–62 (Jan. 15, 2013).

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topic and the EPA is not making any revisions to the PSD requirements for O_3 in this action to address this issue. Therefore, the EPA is not responding to those comments at this time, consistent with its general approach to comments on implementation topics described above. However, to help address this concern raised by commenters, the EPA is considering issuing additional guidance on how PSD offsets can be implemented.

3. Nonattainment NSR

Part D of title I of the CAA includes preconstruction review and permitting requirements for new major stationary sources and major modifications when they locate in areas designated nonattainment for a particular pollutant. The relevant part D requirements are typically referred to as the nonattainment NSR (NNSR) program. The EPA regulations for the NNSR program are contained at 40 CFR 51.165, 52.24 and part 51 Appendix S. The EPA's minimum requirements for a NNSR program to be approvable into a SIP are contained in 40 CFR 51.165. Appendix S to 40 CFR part 51 contains an interim NNSR program. This interim program enables implementation of NNSR permitting in nonattainment areas that lack a SIP-approved NNSR permitting program for the particular nonattainment pollutant, and the interim program can be applied during the time between the date of the relevant nonattainment designation and the date on which the EPA approves into the SIP a NNSR program or additional components of an NNSR program for a particular pollutant.[250] This interim program is commonly known as the Emissions Offset Interpretative Rule, and is applicable to all criteria pollutants, including O_3.[251]

The EPA is not modifying any existing NNSR requirements in this rulemaking. Under the CAA, area designations for new or revised NAAQS are addressed subsequent to the effective date of the new or revised NAAQS. If the EPA determines that any revisions to the existing NNSR requirements, including those in Appendix S, are appropriate, the EPA expects, at a later date contemporaneous with the designation process for the revised O_3 NAAQS, to propose those revisions. If any changes are proposed to Appendix S requirements, the EPA anticipates that it would intend for those changes to become effective no later than the effective date of the area designations. This timing would allow air agencies that lack an approved NNSR program for O_3 to use the relevant Appendix S provisions to issue NNSR permits addressing O_3 on and after the effective date of designations of new nonattainment areas for O_3 until such time as a NNSR program for O_3 is approved into the SIP.[252]

For NNSR, new major stationary sources and major modifications for O_3 must comply with the Lowest Achievable Emission Rate (LAER) requirements as defined in the CAA and NNSR rules, and must perform other analyses and satisfy other requirements under section 173 of the CAA. For example, under CAA section 173(c) emissions reductions, known as emissions offsets, must be secured to offset the increased emissions of the air pollutant (including the relevant precursors) from the new or modified source by an equal or greater reduction, as applicable, of such pollutant. The appropriate emissions offset needed for a particular source will depend upon the classification for the O_3 nonattainment area in which the source or modification will locate, such that areas with more severe nonattainment classifications have more stringent offset requirements. This ranges from 1.1:1 for areas classified as Marginal to 1.5:1 for areas classified as Extreme. *See, e.g.,* CAA section 182, 40 CFR 51.165(a)(9) and 40 CFR part 51 Appendix S section IV.G.2.

To facilitate continued economic development in nonattainment areas, many states have established offset banks or registries.[253] Such banks or registries can help new or modified major stationary source owners meet offset requirements by streamlining identification and access to available emissions reductions. Some states have established offset banks to help ensure a consistent method for generating, validating and transferring NO_X and VOC offsets. Offsets in these areas are generated by emissions reductions that meet specific creditability criteria set forth by the SIP consistent with the EPA regulations. *See* 40 CFR 51.165(a)(3)(ii)(A)-(J) and part 51 Appendix S section IV.C. The EPA received comments expressing concern about the limited availability of offsets in nonattainment areas. Since the EPA did not propose, and is not finalizing, any amendments related to the NNSR offset provisions, the EPA is not responding to those comments at this time, consistent with the EPA's general approach to comment on implementation topics as described above.

D. Transportation and General Conformity

1. What are transportation and general conformity?

Conformity is required under CAA section 176(c) to ensure that federal actions are consistent with (''conform to'') the purpose of the SIP. Conformity to the purpose of the SIP means that federal activities will not cause new air quality violations, worsen existing violations, or delay timely attainment of the relevant NAAQS or interim reductions and milestones. Conformity applies to areas that are designated nonattainment, and those nonattainment areas redesignated to attainment with a CAA section 175A maintenance plan after 1990 (''maintenance areas'').

The EPA's Transportation Conformity Rule (40 CFR 51.390 and part 93, subpart A) establishes the criteria and procedures for determining whether transportation activities conform to the SIP. These activities include adopting, funding or approving transportation plans, transportation improvement programs (TIPs) and federally supported highway and transit projects. For further information on conformity rulemakings, policy guidance and outreach materials, *see* the EPA's Web site at *http://www.epa.gov/otaq/stateresources/transconf/index.htm*. The EPA may issue future transportation conformity guidance as needed to implement a revised O_3 NAAQS.

With regard to general conformity, the EPA first promulgated general conformity regulations in November 1993. (40 CFR part 51, subpart W, 40 CFR part 93, subpart B) Subsequently the EPA finalized revisions to the general conformity regulations on April 5, 2010. (75 FR 17254–17279). Besides ensuring that federal actions not covered by the transportation conformity rule will not interfere with the SIP, the general conformity program also fosters communications between federal agencies and state/local air quality agencies, provides for public notification of and access to federal agency conformity determinations, and allows for air quality review of

[250] *See* Appendix S, Part I; 40 CFR 52.24(k).

[251] As appropriate, certain NNSR requirements under 40 CFR 51.165 or Appendix S can also apply to sources and modifications located in areas that are designated attainment or unclassifiable in the Ozone Transport Region. *See, e.g.,* CAA 184(b)(2), 40 CFR 52.24(k).

[252] States with SIP-approved NNSR programs for O_3 should evaluate that program to determine whether they can continue to issue permits under their approved program or whether revisions to their program are necessary to address the revised O_3 NAAQS.

[253] *See,* for example, emission reduction credit banking programs in Ohio (OAC Chapter 3745–1111) and California (H&SC Section 40709).

individual federal actions. More information on the general conformity program is available at *http://www.epa.gov/air/genconform/*.

2. When would transportation and general conformity apply to areas designated nonattainment for the revised O_3 NAAQS?

Transportation and general conformity apply one year after the effective date of nonattainment designations for the revised O_3 NAAQS. This is because CAA section 176(c)(6) provides a 1-year grace period from the effective date of initial designations for any revised NAAQS before transportation and general conformity apply in areas newly designated nonattainment for a specific pollutant and NAAQS.

3. Impact of a Revised O_3 NAAQS on a State's Existing Transportation and/or General Conformity SIP

In this final rule, the EPA is revising the O_3 NAAQS, but is not making specific changes to its transportation or general conformity regulations. Therefore, states should not need to revise their transportation and/or general conformity SIPs. While we are not making any revisions to the general conformity regulations at this time, we recommend, when areas develop SIPs for a revised O_3 NAAQS, that state and local air quality agencies work with federal agencies with large emitting activities that are subject to the general conformity regulations to establish an emissions budget for those facilities and activities in order to facilitate future conformity determinations under the conformity regulations. Finally, states with existing conformity SIPs and new nonattainment areas may also need to revise their conformity SIPs in order to ensure the state regulations apply in any newly designated areas.

Because significant tracts of land under federal management may be included in nonattainment area boundaries, the EPA encourages state and local air quality agencies to work with federal agencies to assess and develop emissions budgets that consider emissions from projects subject to general conformity, including emissions from fire on wildland, in any baseline, modeling and SIP attainment inventory. Where appropriate, states, land managers, and landowners may also consider developing plans to ensure that fuel accumulations are addressed Information is available from DOI and USDA Forest Service on the ecological role of fire and on smoke management programs and basic smoke management practices.[254]

If this is the first time that transportation conformity will apply in a state, such a state is required by the statute and EPA regulations to submit a SIP revision that addresses three specific transportation conformity requirements that address consultation procedures and written commitments to control or mitigation measures associated with conformity determinations for transportation plans, TIPs or projects. (40 CFR 51.390) Additional information and guidance can be found in the EPA's ''Guidance for Developing Transportation Conformity State Implementation Plans'' (*http://www.epa.gov/otaq/stateresources/transconf/policy/420b09001.pdf*).

E. Regional and International Pollution Transport

1. Interstate Transport

The CAA contains provisions that specifically address and require regulation of the interstate transport of air pollution that does not otherwise qualify for data exclusion under the Act's exceptional events provisions. As previously noted, emissions from events, such as wildfires, may qualify as exceptional events and may be transported across jurisdictional boundaries. The EPA intends to address the transport of event-related emissions in our upcoming proposed revisions to the Exceptional Events Rule and draft guidance document addressing the Exceptional Events Rule criteria for wildfires that could affect O_3 concentrations. The EPA encourages affected air agencies to coordinate with their EPA regional office to identify approaches to evaluate the potential impacts of transported event-related emissions and determine the most appropriate information and analytical methods for each area's unique situation.

CAA section 110(a)(2)(D)(i)(I), Interstate Transport—CAA section 110(a)(2)(D)(i)(I) requires states to develop and implement a SIP to address the interstate transport of emissions. Specifically, this provision requires the SIP to prohibit ''any source or other type of emissions activity within the state'' that would ''significantly contribute to nonattainment'' of any NAAQS in another state, or that would ''interfere with maintenance'' of any NAAQS in another state. When EPA promulgates or revises a NAAQS, each state is required to submit a SIP addressing this interstate transport provision within 3 years.

CAA section 126, Interstate Transport—CAA section 126(b) provides states and political subdivisions with a mechanism to petition the Administrator for a finding that ''any major source or group of stationary sources emits or would emit any air pollution in violation of the prohibition of [CAA section 110(a)(2)(D)(i)(I)].'' [255] Where the EPA makes such finding, the source is allowed to operate beyond a 3-month period after such finding only if the EPA establishes emissions limitations and a compliance schedule designated to bring the source into compliance as expeditiously as practicable, but no later than three years after such finding. This mechanism is available to downwind states and political subdivisions, regardless of designation status, that would be affected by emissions from upwind states.

2. International Transport

The agency is active in work to reduce the international transport of O_3 and other pollutants that can contribute to ''background'' O_3 levels in the U.S. Under the Convention on Long-Range Transboundary Air Pollution (LRTAP) of the United Nations Economic Commission for Europe, the U.S. has been a party to the Protocol to Abate Acidification, Eutrophication, and Ground-level Ozone (known as the Gothenburg Protocol) since 2005.The U.S. is also active in the LRTAP Task Force for Hemispheric Transport of Air Pollution. The U.S. has worked bilaterally with Canada under the US-Canada Air Quality Agreement to adopt an Ozone Annex to address transboundary O_3 impacts and continues to work with China on air quality management activities. This work includes supporting China's efforts to rapidly deploy power plant pollution controls that can achieve NO_X reductions of at least 80 to 90%. The U.S. also continues to work bilaterally with Mexico on the Border 2020 program to support efforts to improve environmental conditions in the border region. One of the main goals of the program is to reduce air pollution, including emissions that can cause transboundary O_3 impacts.

[254] USDA Forest Service and Natural Resources Conservation Service, Basic Smoke Management Practices Tech Note, October 2011, *http://www.nrcs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb1046311.pdf*.

[255] The text of section 126 codified in the United States Code cross references section 110(a)(2)(D)(ii) instead of section 110(a)(2)(D)(i). The courts have confirmed that this is a scrivener's error and the correct cross reference is to section 110(a)(2)(D)(i), See *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032, 1040–44 (D.C. Cir. 2001).

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Clean Air Act section 179B recognizes the possibility that certain nonattainment areas may be impacted by O_3 or O_3 precursor emissions from international sources beyond the regulatory jurisdiction of the state. The EPA's science review suggests that the influence of international sources on U.S. O_3 levels will be largest in locations that are in the immediate vicinity of an international border with Canada or Mexico. The science review also cites two recent studies which indicate that intercontinental transport of pollution, along with other natural sources and local pollutant sources, can affect O_3 air quality in the western U.S. under specific conditions. (U.S. EPA 2013, p. 3–140). Section 179B allows states to consider in their attainment plans and demonstrations whether an area might meet the O_3 NAAQS by the attainment date ''but for'' emissions contributing to the area originating outside the U.S. If a state is unable to demonstrate attainment of the NAAQS in such an area impacted by international transport after adopting all reasonably available control measures (*e.g.,* RACM, including RACT, as required by CAA section 182(b)), the EPA can nonetheless approve the CAA-required state attainment plan and demonstration using the authority in section 179B.

When the EPA approves this type of attainment plan and demonstration, and there would be no adverse consequence for a finding that the area failed to attain the NAAQS by the relevant attainment date. States can also avoid potential sanctions and FIPs that would otherwise apply for failure to submit a required SIP submission or failure to submit an approvable SIP submission. For example, section 179B explicitly provides that the area shall not be reclassified to the next highest classification or required to implement a section 185 penalty fee program if a state meets the applicable criteria.

Section 179B authority does not allow an area to avoid a nonattainment designation or for the area to be classified with a lower classification than is indicated by actual ambient air quality. Section 179B also does not provide for any relaxation of mandatory emissions control measures (including contingency measures) or the prescribed emissions reductions necessary to achieve periodic emissions reduction progress requirements. In this way, section 179B insures that states will take actions to mitigate the public health impacts of exposure to ambient levels of pollution that violate the NAAQS by imposing reasonable control measures on the sources that *are* within the jurisdiction of the state while also authorizing EPA to approve such attainment plans and demonstrations even though they do not fully address the public health impacts of international transport. Also, generally, monitoring data influenced by international transport may not be excluded from regulatory determinations. However, depending on the nature and scope of international emissions events affecting air quality in the U.S., the event-influenced data may qualify for exclusion under the Exceptional Events Rule. The EPA encourages affected air agencies to coordinate with their EPA regional office to identify approaches to evaluate the potential impacts of international transport and to determine the most appropriate information and analytical methods for each area's unique situation. The EPA will also work with states that are developing attainment plans for which section 179B is relevant, and ensure the states have the benefit of the EPA's understanding of international transport of ozone and ozone precursors.

The EPA has used section 179B authority previously to approve attainment plans for Mexican border areas in El Paso, TX (O_3, PM_{10}, and CO plans); and Nogales, AZ (PM_{10} plan). The 24-hour PM_{10} attainment plan for Nogales, AZ, was approved by EPA as sufficient to demonstrate attainment of the NAAQS by the Moderate classification deadline, but for international emissions sources in the Nogales Municipality, Mexico area (77 FR 38400, June 27, 2012).

States are encouraged to consult with their EPA Regional Office to establish appropriate technical requirements for these analyses.

IX. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the document, *Regulatory Impact Analysis of the Final National Ambient Air Quality Standards for Ground-Level Ozone,* October 2015. A copy of the analysis is available in the RIA docket (EPA–HQ–OAR–2013–0169) and the analysis is briefly summarized here. The RIA estimates the costs and monetized human health and welfare benefits of attaining three alternative O_3 NAAQS nationwide. Specifically, the RIA examines the alternatives of 65 ppb and 70 ppb. The RIA contains illustrative analyses that consider a limited number of emissions control scenarios that states and Regional Planning Organizations might implement to achieve these alternative O_3 NAAQS. However, the CAA and judicial decisions make clear that the economic and technical feasibility of attaining ambient standards are not to be considered in setting or revising NAAQS, although such factors may be considered in the development of state plans to implement the standards. Accordingly, although an RIA has been prepared, the results of the RIA have not been considered in issuing this final rule.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA). The information collection requirements are not enforceable until OMB approves them. The Information Collection Request (ICR) document prepared by the EPA for these revisions has been assigned EPA ICR #2313.04.

The information collected and reported under 40 CFR part 58 is needed to determine compliance with the NAAQS, to characterize air quality and associated health and ecosystems impacts, to develop emission control strategies, and to measure progress for the air pollution program. We are extending the length of the required O_3 monitoring season in 32 states and the District of Columbia and the revised O_3 monitoring seasons will become effective on January 1, 2017. We are also revising the PAMS monitoring requirements to reduce the number of required PAMS sites while improving spatial coverage, and requiring states in moderate or above O_3 non-attainment areas and the O_3 transport region to develop an enhanced monitoring plan as part of the PAMS requirements. Monitoring agencies will need to comply with the PAMS requirements by June 1, 2019. In addition, we are revising the O_3 FRM to establish a new, additional technique for measuring O_3 in the ambient air. It will be

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incorporated into the existing O_3 FRM, using the same calibration procedure in Appendix D of 40 CFR part 50. We are also making changes to the procedures for testing performance characteristics and determining comparability between candidate FEMs and reference methods.

For the purposes of ICR number 2313.04, the burden figures represent the burden estimate based on the requirements contained in this rule. The burden estimates are for the 3-year period from 2016 through 2018. The implementation of the PAMS changes will occur beyond the time frame of this ICR with implementation occurring in 2019. The cost estimates for the PAMS network (including revisions) will be captured in future routine updates to the Ambient Air Quality Surveillance ICR that are required every 3 years by OMB. The addition of a new FRM in 40 CFR part 50 and revisions to the O_3 FEM procedures for testing performance characteristics in 40 CFR part 53 does not add any additional information collection requirements.

The ICR burden estimates are associated with the changes to the O_3 seasons in this final rule. This information collection is estimated to involve 158 respondents for a total cost of approximately $24,597,485 (total capital, labor, and operation and maintenance) plus a total burden of 339,930 hours for the support of all operational aspects of the entire O_3 monitoring network. The labor costs associated with these hours are $20,209,966. Also included in the total are other costs of operations and maintenance of $2,254,334 and equipment and contract costs of $2,133,185. The actual labor cost increase to expand the O_3 monitoring seasons is $2,064,707. In addition to the costs at the state, local, and tribal air quality management agencies, there is a burden to EPA of 41,418 hours and $2,670,360. Burden is defined at 5 CFR 1320.3(b). State, local, and tribal entities are eligible for state assistance grants provided by the federal government under the CAA which can be used for related activities. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Rather, this rule establishes national standards for allowable concentrations of O_3 in ambient air as required by section 109 of the CAA. See also *American Trucking Associations* v. *EPA,* 175 F. 3d at 1044–45 (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities). Similarly, the revisions to 40 CFR part 58 address the requirements for states to collect information and report compliance with the NAAQS and will not impose any requirements on small entities. Similarly, the addition of a new FRM in 40 CFR part 50 and revisions to the FEM procedures for testing in 40 CFR part 53 will not impose any requirements on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded federal mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The revisions to the O_3 NAAQS impose no enforceable duty on any state, local, or tribal governments or the private sector beyond those duties already established in the CAA. The expected costs associated with the monitoring requirements are described in the EPA's ICR document, and these costs are not expected to exceed $100 million in the aggregate for any year.

Furthermore, as indicated previously, in setting NAAQS the EPA cannot consider the economic or technological feasibility of attaining ambient air quality standards, although such factors may be considered to a degree in the development of state plans to implement the standards (see *American Trucking Associations* v. *EPA,* 175 F. 3d at 1043 [noting that because the EPA is precluded from considering costs of implementation in establishing NAAQS, preparation of a RIA pursuant to the UMRA would not furnish any information which the court could consider in reviewing the NAAQS]). With regard to the sections of the rule preamble discussing implementation of the revisions to the O_3 NAAQS, the CAA imposes the obligation for states to submit SIPs to implement the NAAQS for O_3. To the extent the EPA's discussion of implementation topics in this final rule may reflect some interpretations of those requirements, those interpretations do not impose obligations beyond the duties already established in the CAA and thus do not constitute a federal mandate for purposes of UMRA. The EPA is also adopting a grandfathering provision for certain PSD permits in this action, as described above. However, that provision does not impose any mandate on any state, local, or tribal government or the private sector, but rather provides relief from requirements that would otherwise result from the new standards. In addition, the EPA is not requiring states to revise their SIPs to include such a provision.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It does not have a substantial direct effect on one or more Indian tribes. This rule provides increased protection from adverse effects of ozone for the entire country, including for sensitive populations, and tribes are not obligated to adopt or implement any NAAQS. In addition, tribes are not obligated to conduct ambient monitoring for O_3 or to adopt the ambient monitoring requirements of 40 CFR part 58. Even if this action were determined to have tribal implications within the meaning of Executive Order 13175, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. Thus, consultation under Executive Order 13175 was not required.

Nonetheless, consistent with the ''EPA Policy on Consultation and Coordination with Indian Tribes'', the EPA offered government-to-government consultation on the proposed rule. No tribe requested government-to-government consultation with the EPA on this rule. In addition, the EPA conducted outreach to tribal environmental professionals, which included participation in the Tribal Air call sponsored by the National Tribal Air Association, and two other calls available to tribal environmental professionals. During the public comment period we received comments on the proposed rule from seven tribes and three tribal organizations.

G. Executive Order 13045: Protection of Children From Environmental Health & Safety Risks

This action is subject to Executive Order 13045 because it is an

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economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health risk addressed by this action may have a disproportionate effect on children. The rule will establish uniform NAAQS for O_3; these standards are designed to protect public health with an adequate margin of safety, as required by CAA section 109. However, the protection offered by these standards may be especially important for children because children, especially children with asthma, along with other at-risk populations [256] such as all people with lung disease and people active outdoors, are at increased risk for health effects associated with exposure to O_3 in ambient air. Because children are considered an at-risk lifestage, we have carefully evaluated the environmental health effects of exposure to O_3 pollution among children. Discussions of the results of the evaluation of the scientific evidence, policy considerations, and the exposure and risk assessments pertaining to children are contained in sections II.B and II.C of this preamble.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The purpose of this rule is to establish revised NAAQS for O_3, establish an additional FRM, revise FEM procedures for testing, and revises air quality surveillance requirements. The rule does not prescribe specific pollution control strategies by which these ambient standards and monitoring revisions will be met. Such strategies will be developed by states on a case-by-case basis, and the EPA cannot predict whether the control options selected by states will include regulations on energy suppliers, distributors, or users. Thus, the EPA concludes that this rule is not likely to have any adverse energy effects and does not constitute a significant energy action as defined in Executive Order 13211.

I. National Technology Transfer and Advancement Act

This rulemaking involves environmental monitoring and measurement. Consistent with the Agency's Performance Based Measurement System (PBMS), the EPA is not requiring the use of specific, prescribed analytical methods. Rather, the Agency is allowing the use of any method that meets the prescribed performance criteria. Ambient air concentrations of O_3 are currently measured by the FRM in 40 CFR part 50, Appendix D (Measurement Principle and Calibration Procedure for the Measurement of Ozone in the Atmosphere) or by FEM that meet the requirements of 40 CFR part 53. Procedures are available in part 53 that allow for the approval of an FEM for O_3 that is similar to the FRM. Any method that meets the performance criteria for a candidate equivalent method may be approved for use as an FEM. This approach is consistent with EPA's PBMS. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. The EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the specified performance criteria.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action will not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations or indigenous peoples. The action described in this notice is to strengthen the NAAQS for O_3.

The primary NAAQS are established at a level that is requisite to protect public health, including the health of sensitive or at-risk groups, with an adequate margin of safety. The NAAQS decisions are based on an explicit and comprehensive assessment of the current scientific evidence and associated exposure/risk analyses. More specifically, EPA expressly considers the available information regarding health effects among at-risk populations, including that available for low-income populations and minority populations, in decisions on NAAQS. Where low-income populations or minority populations are among the at-risk populations, the decision on the standard is based on providing protection for these and other at-risk populations and lifestages. Where such populations are not identified as at-risk populations, a NAAQS that is established to provide protection to the at-risk populations would also be expected to provide protection to all other populations, including low-income populations and minority populations.

The ISA, HREA, and PA for this review, which include identification of populations at risk from O_3 health effects, are available in the docket, EPA–HQ–OAR–2008–0699. The information on at-risk populations for this NAAQS review is summarized and considered earlier in this preamble (see section II.A). This final rule increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority populations, low-income populations or indigenous peoples. This rule establishes uniform national standards for O_3 in ambient air that, in the Administrator's judgment, protect public health, including the health of sensitive groups, with an adequate margin of safety.

Although it is part of a separate docket (EPA–HQ–OAR–2013–0169) and is not part of the rulemaking record for this action, EPA has prepared a RIA of this decision. As part of the RIA, a demographic analysis was conducted. While, as noted in the RIA, the demographic analysis is not a full quantitative, site-specific exposure and risk assessment, that analysis examined demographic characteristics of persons living in areas with poor air quality relative to the proposed standard. Specifically, Chapter 9, section 9.10 (page 9–7) and Appendix 9A of the RIA describe this proximity and socio-demographic analysis. This analysis found that in areas with poor air quality relative to the revised standard,[257] the representation of minority populations was slightly greater than in the U.S. as a whole. Because the air quality in these areas does not currently meet the revised standard, populations in these areas would be expected to benefit from implementation of the strengthened standard, and, thus, would be more affected by strategies to attain the revised standard. This analysis, which evaluates the potential implications for minority populations and low-income populations of future air pollution control actions that state and local agencies may consider in implementing the revised O_3 NAAQS described in this decision notice are discussed in Appendix 9A of the RIA. The RIA is available on the Web, through the EPA's Technology Transfer Network Web site at *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html* and

[256] As used here and similarly throughout this document, the term population refers to people having a quality or characteristic in common, including a specific pre-existing illness or a specific age or lifestage.

[257] This refers to monitored areas with O_3 design values above the revised and alternative standards.

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in the RIA docket (EPA–HQ–OAR–2013–0169). As noted above, although an RIA has been prepared, the results of the RIA have not been considered in issuing this final rule.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

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List of Subjects

40 CFR Part 50

Environmental protection, Air pollution control, Carbon monoxide, Lead, Nitrogen dioxide, Ozone, Particulate matter, Sulfur oxides.

40 CFR Part 51

Environmental protection, Administrative practices and procedures, Air pollution control, Intergovernmental relations.

40 CFR Part 52

Environmental Protection, Administrative practices and procedures, Air pollution control, Incorporation by reference, Intergovernmental relations.

40 CFR Part 53

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 58

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: October 1, 2015.

Gina McCarthy,

Administrator.

For the reasons set forth in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 50—NATIONAL PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS

■ 1. The authority citation for part 50 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Amend §50.14 by:

■ a. Revising paragraphs (c)(2)(iii) and (vi) and (c)(3)(i); and

■ b. Removing and reserving paragraphs (c)(2)(iv) and (v) and (c)(3)(ii) and (iii).

The revisions read as follows:

§ 50.14 Treatment of air quality monitoring data influenced by exceptional events.

* * * * *

(c) * * *

(2) * * *

(iii) Flags placed on data as being due to an exceptional event together with an initial description of the event shall be submitted to EPA not later than July 1st of the calendar year following the year in which the flagged measurement occurred, except as allowed under paragraph (c)(2)(vi) of this section.

* * * * *

(vi) Table 1 identifies the data submission process for a new or revised NAAQS. This process shall apply to those data that will or may influence the initial designation of areas for any new or revised NAAQS.

TABLE 1—SCHEDULE FOR FLAGGING AND DOCUMENTATION SUBMISSION FOR DATA INFLUENCED BY EXCEPTIONAL EVENTS FOR USE IN INITIAL AREA DESIGNATIONS

Exceptional events/regulatory action	Exceptional events deadline schedule [d]
Flagging and initial event description deadline for data years 1, 2 and 3.[a]	If state and tribal initial designation recommendations for a new/revised NAAQS are due August through January, then the flagging and initial event description deadline will be the July 1 prior to the recommendation deadline. If state and tribal recommendations for a new/revised NAAQS are due February through July, then the flagging and initial event description deadline will be the January 1 prior to the recommendation deadline.
Exceptional events demonstration submittal deadline for data years 1, 2 and 3.[a]	No later than the date that state and tribal recommendations are due to EPA.
Flagging, initial event description and exceptional events demonstration submittal deadline for data year 4 [b] and, where applicable, data year 5.[c]	By the last day of the month that is 1 year and 7 months after promulgation of a new/revised NAAQS, unless either option a or b applies. a. If the EPA follows a 3-year designation schedule, the deadline is 2 years and 7 months after promulgation of a new/revised NAAQS. b. If the EPA notifies the state/tribe that it intends to complete the initial area designations process according to a schedule between 2 and 3 years, the deadline is 5 months prior to the date specified for final designations decisions in such EPA notification.

[a] Where data years 1, 2, and 3 are those years expected to be considered in state and tribal recommendations.

[b] Where data year 4 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under the standard designations schedule.

[c] Where data year 5 is the additional year of data that the EPA may consider when it makes final area designations for a new/revised NAAQS under an extended designations schedule.

[d] The date by which air agencies must certify their ambient air quality monitoring data in AQS is annually on May 1 of the year following the year of data collection as specified in 40 CFR 58.15(a)(2). In some cases, however, air agencies may choose to certify a prior year's data in advance of May 1 of the following year, particularly if the EPA has indicated its intent to promulgate final designations in the first 8 months of the calendar year. Data flagging, initial event description and exceptional events demonstration deadlines for "early certified" data will follow the deadlines for "year 4" and "year 5" data.

(3) *Submission of demonstrations.* (i) Except as allowed under paragraph (c)(2)(vi) of this section, a State that has flagged data as being due to an exceptional event and is requesting exclusion of the affected measurement data shall, after notice and opportunity for public comment, submit a demonstration to justify data exclusion to EPA not later than the lesser of 3 years following the end of the calendar quarter in which the flagged concentration was recorded or 12 months prior to the date that a regulatory decision must be made by EPA. A State must submit the public comments it received along with its demonstration to EPA.

* * * * *

■ 3. Section 50.19 is added to read as follows:

§ 50.19 National primary and secondary ambient air quality standards for ozone.

(a) The level of the national 8-hour primary ambient air quality standard for ozone (O_3) is 0.070 parts per million (ppm), daily maximum 8-hour average, measured by a reference method based on appendix D to this part and designated in accordance with part 53 of this chapter or an equivalent method designated in accordance with part 53 of this chapter.

(b) The 8-hour primary O_3 ambient air quality standard is met at an ambient air quality monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration is less than or equal to 0.070 ppm, as determined in accordance with appendix U to this part.

(c) The level of the national secondary ambient air quality standard for O_3 is 0.070 ppm, daily maximum 8-hour

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average, measured by a reference method based on appendix D to this part and designated in accordance with part 53 of this chapter or an equivalent method designated in accordance with part 53 of this chapter.

(d) The 8-hour secondary O_3 ambient air quality standard is met at an ambient air quality monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration is less than or equal to 0.070 ppm, as determined in accordance with appendix U to this part.

■ 4. Revise appendix D to part 50 to read as follows:

Appendix D to Part 50—Reference Measurement Principle and Calibration Procedure for the Measurement of Ozone in the Atmosphere (Chemiluminescence Method)

1.0 Applicability.

1.1 This chemiluminescence method provides reference measurements of the concentration of ozone (O_3) in ambient air for determining compliance with the national primary and secondary ambient air quality standards for O_3 as specified in 40 CFR part 50. This automated method is applicable to the measurement of ambient O_3 concentrations using continuous (real-time) sampling and analysis. Additional quality assurance procedures and guidance are provided in 40 CFR part 58, appendix A, and in Reference 14.

2.0 Measurement Principle.

2.1 This reference method is based on continuous automated measurement of the intensity of the characteristic chemiluminescence released by the gas phase reaction of O_3 in sampled air with either ethylene (C_2H_4) or nitric oxide (NO) gas. An ambient air sample stream and a specific flowing concentration of either C_2H_4 (ET–CL method) or NO (NO–CL method) are mixed in a measurement cell, where the resulting chemiluminescence is quantitatively measured by a sensitive photo-detector. References 8–11 describe the chemiluminescence measurement principle.

2.2 The measurement system is calibrated by referencing the instrumental chemiluminescence measurements to certified O_3 standard concentrations generated in a dynamic flow system and assayed by photometry to be traceable to a National Institute of Standards and Technology (NIST) standard reference photometer for O_3 (see Section 4, Calibration Procedure, below).

2.3 An analyzer implementing this measurement principle is shown schematically in Figure 1. Designs implementing this measurement principle must include: an appropriately designed mixing and measurement cell; a suitable quantitative photometric measurement system with adequate sensitivity and wavelength specificity for O_3; a pump, flow control, and sample conditioning system for sampling the ambient air and moving it into and through the measurement cell; a sample air dryer as necessary to meet the water vapor interference limit requirement specified in subpart B of part 53 of this chapter; a means to supply, meter, and mix a constant, flowing stream of either C_2H_4 or NO gas of fixed concentration with the sample air flow in the measurement cell; suitable electronic control and measurement processing capability; and other associated apparatus as may be necessary. The analyzer must be designed and constructed to provide accurate, repeatable, and continuous measurements of O_3 concentrations in ambient air, with measurement performance that meets the requirements specified in subpart B of part 53 of this chapter.

2.4 An analyzer implementing this measurement principle and calibration procedure will be considered a federal reference method (FRM) only if it has been designated as a reference method in accordance with part 53 of this chapter.

2.5 *Sampling considerations.* The use of a particle filter on the sample inlet line of a chemiluminescence O_3 FRM analyzer is required to prevent buildup of particulate matter in the measurement cell and inlet components. This filter must be changed weekly (or at least often as specified in the manufacturer's operation/instruction manual), and the sample inlet system used with the analyzer must be kept clean, to avoid loss of O_3 in the O_3 sample air prior to the concentration measurement.

3.0 Interferences.

3.1 Except as described in 3.2 below, the chemiluminescence measurement system is inherently free of significant interferences from other pollutant substances that may be present in ambient air.

3.2 A small sensitivity to variations in the humidity of the sample air is minimized by a sample air dryer. Potential loss of O_3 in the inlet air filter and in the air sample handling components of the analyzer and associated exterior air sampling components due to buildup of airborne particulate matter is minimized by filter replacement and cleaning of the other inlet components.

4.0 Calibration Procedure.

4.1 *Principle.* The calibration procedure is based on the photometric assay of O_3 concentrations in a dynamic flow system. The concentration of O_3 in an absorption cell is determined from a measurement of the amount of 254 nm light absorbed by the sample. This determination requires knowledge of (1) the absorption coefficient (α) of O_3 at 254 nm, (2) the optical path length (l) through the sample, (3) the transmittance of the sample at a nominal wavelength of 254 nm, and (4) the temperature (T) and pressure (P) of the sample. The transmittance is defined as the ratio I/I_0, where I is the intensity of light which passes through the cell and is sensed by the detector when the cell contains an O_3 sample, and I_0 is the intensity of light which passes through the cell and is sensed by the detector when the cell contains zero air. It is assumed that all conditions of the system, except for the contents of the absorption cell, are identical during measurement of I and I_0. The quantities defined above are related by the Beer-Lambert absorption law,

$$\text{Transmitance} = \frac{I}{I_0} = e^{-\alpha cl} \qquad (1)$$

Where:

α = absorption coefficient of O_3 at 254 nm = 308 ±4 atm¥1 cm¥1 at 0 °C and 760 torr,[1, 2, 3, 4, 5, 6, 7]

c = O_3 concentration in atmospheres, and

l = optical path length in cm.

A stable O_3 generator is used to produce O_3 concentrations over the required calibration concentration range. Each O_3 concentration is determined from the measurement of the transmittance (I/I_0) of the sample at 254 nm with a photometer of path length l and calculated from the equation,

$$c(\text{atm}) = -\frac{1}{\alpha l}\left(\ln\frac{I}{I_0}\right) \qquad (2a)$$

or

$$c(\text{ppm}) = -\frac{10^6}{\alpha l}\left(\ln\frac{I}{I_0}\right). \qquad (2b)$$

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The calculated O_3 concentrations must be corrected for O_3 losses, which may occur in the photometer, and for the temperature and pressure of the sample.

4.2 *Applicability.* This procedure is applicable to the calibration of ambient air O_3 analyzers, either directly or by means of a transfer standard certified by this procedure. Transfer standards must meet the requirements and specifications set forth in Reference 12.

4.3 *Apparatus.* A complete UV calibration system consists of an O_3 generator, an output port or manifold, a photometer, an appropriate source of zero air, and other components as necessary. The configuration must provide a stable O_3 concentration at the system output and allow the photometer to accurately assay the output concentration to the precision specified for the photometer (4.3.1). Figure 2 shows a commonly used configuration and serves to illustrate the calibration procedure, which follows. Other configurations may require appropriate variations in the procedural steps. All connections between components in the calibration system downstream of the O_3 generator must be of glass, Teflon, or other relatively inert materials. Additional information regarding the assembly of a UV photometric calibration apparatus is given in Reference 13. For certification of transfer standards which provide their own source of O_3, the transfer standard may replace the O_3 generator and possibly other components shown in Figure 2; see Reference 12 for guidance.

4.3.1 *UV photometer.* The photometer consists of a low-pressure mercury discharge lamp, (optional) collimation optics, an absorption cell, a detector, and signal-processing electronics, as illustrated in Figure 2. It must be capable of measuring the transmittance, I/I_0, at a wavelength of 254 nm with sufficient precision such that the standard deviation of the concentration measurements does not exceed the greater of 0.005 ppm or 3% of the concentration. Because the low-pressure mercury lamp radiates at several wavelengths, the photometer must incorporate suitable means to assure that no O_3 is generated in the cell by the lamp, and that at least 99.5% of the radiation sensed by the detector is 254 nm radiation. (This can be readily achieved by prudent selection of optical filter and detector response characteristics.) The length of the light path through the absorption cell must be known with an accuracy of at least 99.5%. In addition, the cell and associated plumbing must be designed to minimize loss of O_3 from contact with cell walls and gas handling components. See Reference 13 for additional information.

4.3.2 *Air flow controllers.* Air flow controllers are devices capable of regulating air flows as necessary to meet the output stability and photometer precision requirements.

4.3.3 *Ozone generator.* The ozone generator used must be capable of generating stable levels of O_3 over the required concentration range.

4.3.4 *Output manifold.* The output manifold must be constructed of glass, Teflon, or other relatively inert material, and should be of sufficient diameter to insure a negligible pressure drop at the photometer connection and other output ports. The system must have a vent designed to insure atmospheric pressure in the manifold and to prevent ambient air from entering the manifold.

4.3.5 *Two-way valve.* A manual or automatic two-way valve, or other means is used to switch the photometer flow between zero air and the O_3 concentration.

4.3.6 *Temperature indicator.* A device to indicate temperature must be used that is accurate to ± 1 °C.

4.3.7 *Barometer or pressure indicator.* A device to indicate barometric pressure must be used that is accurate to ± 2 torr.

4.4 Reagents.

4.4.1 *Zero air.* The zero air must be free of contaminants which would cause a detectable response from the O_3 analyzer, and it must be free of NO, C_2H_4, and other species which react with O_3. A procedure for generating suitable zero air is given in Reference 13. As shown in Figure 2, the zero air supplied to the photometer cell for the I_0 reference measurement must be derived from the same source as the zero air used for generation of the O_3 concentration to be assayed (I measurement). When using the photometer to certify a transfer standard having its own source of O_3, see Reference 12 for guidance on meeting this requirement.

4.5 Procedure.

4.5.1 *General operation.* The calibration photometer must be dedicated exclusively to use as a calibration standard. It must always be used with clean, filtered calibration gases, and never used for ambient air sampling. A number of advantages are realized by locating the calibration photometer in a clean laboratory where it can be stationary, protected from the physical shock of transportation, operated by a responsible analyst, and used as a common standard for all field calibrations via transfer standards.

4.5.2 *Preparation.* Proper operation of the photometer is of critical importance to the accuracy of this procedure. Upon initial operation of the photometer, the following steps must be carried out with all quantitative results or indications recorded in a chronological record, either in tabular form or plotted on a graphical chart. As the performance and stability record of the photometer is established, the frequency of these steps may be reduced to be consistent with the documented stability of the photometer and the guidance provided in Reference 12.

4.5.2.1 *Instruction manual.* Carry out all set up and adjustment procedures or checks as described in the operation or instruction manual associated with the photometer.

4.5.2.2 *System check.* Check the photometer system for integrity, leaks, cleanliness, proper flow rates, etc. Service or replace filters and zero air scrubbers or other consumable materials, as necessary.

4.5.2.3 *Linearity.* Verify that the photometer manufacturer has adequately established that the linearity error of the photometer is less than 3%, or test the linearity by dilution as follows: Generate and assay an O_3 concentration near the upper range limit of the system or appropriate calibration scale for the instrument, then accurately dilute that concentration with zero air and re-assay it. Repeat at several different dilution ratios. Compare the assay of the original concentration with the assay of the diluted concentration divided by the dilution ratio, as follows

$$E = \frac{A_1 - A_2/R}{A_1} \times 100\% \qquad (3)$$

Where:

E = linearity error, percent
A_1 = assay of the original concentration
A_2 = assay of the diluted concentration
R = dilution ratio = flow of original concentration divided by the total flow

The linearity error must be less than 5%. Since the accuracy of the measured flow-rates will affect the linearity error as measured this way, the test is not necessarily conclusive. Additional information on verifying linearity is contained in Reference 13.

4.5.2.4 *Inter-comparison.* The photometer must be inter-compared annually, either directly or via transfer standards, with a NIST standard reference photometer (SRP) or calibration photometers used by other agencies or laboratories.

4.5.2.5 *Ozone losses.* Some portion of the O_3 may be lost upon contact with the photometer cell walls and gas handling components. The magnitude of this loss must be determined and used to correct the calculated O_3 concentration. This loss must not exceed 5%. Some guidelines for quantitatively determining this loss are discussed in Reference 13.

4.5.3 *Assay of O_3 concentrations.* The operator must carry out the following steps to properly assay O_3 concentrations.

4.5.3.1 Allow the photometer system to warm up and stabilize.

4.5.3.2 Verify that the flow rate through the photometer absorption cell, F, allows the cell to be flushed in a reasonably short period of time (2 liter/min is a typical flow). The precision of the measurements is inversely related to the time required for flushing, since the photometer drift error increases with time.

4.5.3.3 Ensure that the flow rate into the output manifold is at least 1 liter/min greater than the total flow rate required by the photometer and any other flow demand connected to the manifold.

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4.5.3.4 Ensure that the flow rate of zero air, Fz, is at least 1 liter/min greater than the flow rate required by the photometer.

4.5.3.5 With zero air flowing in the output manifold, actuate the two-way valve to allow the photometer to sample first the manifold zero air, then Fz. The two photometer readings must be equal ($I = I_0$).

Note: In some commercially available photometers, the operation of the two-way valve and various other operations in section 4.5.3 may be carried out automatically by the photometer.

4.5.3.6 Adjust the O_3 generator to produce an O_3 concentration as needed.

4.5.3.7 Actuate the two-way valve to allow the photometer to sample zero air until the absorption cell is thoroughly flushed and record the stable measured value of Io.

4.5.3.8 Actuate the two-way valve to allow the photometer to sample the O_3 concentration until the absorption cell is thoroughly flushed and record the stable measured value of I.

4.5.3.9 Record the temperature and pressure of the sample in the photometer absorption cell. (See Reference 13 for guidance.)

4.5.3.10 Calculate the O_3 concentration from equation 4. An average of several determinations will provide better precision.

$$[O_3]_{OUT} = \left(\frac{-1}{\alpha l}\ln\frac{I}{I_0}\right)\left(\frac{T}{273}\right)\left(\frac{760}{P}\right)\times\frac{10^6}{L} \qquad (4)$$

Where:

$[O_3]_{OUT}$ = O_3 concentration, ppm
α = absorption coefficient of O_3 at 254 nm = 308 atm¥1 cm¥1 at 0° C and 760 torr
l = optical path length, cm
T = sample temperature, K
P = sample pressure, torr
L = correction factor for O_3 losses from 4.5.2.5 = (1¥fraction of O_3 lost).

Note: Some commercial photometers may automatically evaluate all or part of equation 4. It is the operator's responsibility to verify that all of the information required for equation 4 is obtained, either automatically by the photometer or manually. For ''automatic'' photometers which evaluate the first term of equation 4 based on a linear approximation, a manual correction may be required, particularly at higher O_3 levels. See the photometer instruction manual and Reference 13 for guidance.

4.5.3.11 Obtain additional O_3 concentration standards as necessary by repeating steps 4.5.3.6 to 4.5.3.10 or by Option 1.

4.5.4 *Certification of transfer standards.* A transfer standard is certified by relating the output of the transfer standard to one or more O_3 calibration standards as determined according to section 4.5.3. The exact procedure varies depending on the nature and design of the transfer standard. Consult Reference 12 for guidance.

4.5.5 *Calibration of ozone analyzers.* Ozone analyzers must be calibrated as follows, using O_3 standards obtained directly according to section 4.5.3 or by means of a certified transfer standard.

4.5.5.1 Allow sufficient time for the O_3 analyzer and the photometer or transfer standard to warm-up and stabilize.

4.5.5.2 Allow the O_3 analyzer to sample zero air until a stable response is obtained and then adjust the O_3 analyzer's zero control. Offsetting the analyzer's zero adjustment to +5% of scale is recommended to facilitate observing negative zero drift (if any). Record the stable zero air response as ''Z''.

4.5.5.3 Generate an O_3 concentration standard of approximately 80% of the desired upper range limit (URL) of the O_3 analyzer. Allow the O_3 analyzer to sample this O_3 concentration standard until a stable response is obtained.

4.5.5.4 Adjust the O_3 analyzer's span control to obtain the desired response equivalent to the calculated standard concentration. Record the O_3 concentration and the corresponding analyzer response. If substantial adjustment of the span control is necessary, recheck the zero and span adjustments by repeating steps 4.5.5.2 to 4.5.5.4.

4.5.5.5 Generate additional O_3 concentration standards (a minimum of 5 are recommended) over the calibration scale of the O_3 analyzer by adjusting the O_3 source or by Option 1. For each O_3 concentration standard, record the O_3 concentration and the corresponding analyzer response.

4.5.5.6 Plot the O_3 analyzer responses (vertical or Y-axis) versus the corresponding O_3 standard concentrations (horizontal or X-axis). Compute the linear regression slope and intercept and plot the regression line to verify that no point deviates from this line by more than 2 percent of the maximum concentration tested.

4.5.5.7 *Option 1:* The various O_3 concentrations required in steps 4.5.3.11 and 4.5.5.5 may be obtained by dilution of the O_3 concentration generated in steps 4.5.3.6 and 4.5.5.3. With this option, accurate flow measurements are required. The dynamic calibration system may be modified as shown in Figure 3 to allow for dilution air to be metered in downstream of the O_3 generator. A mixing chamber between the O_3 generator and the output manifold is also required. The flow rate through the O_3 generator (Fo) and the dilution air flow rate (FD) are measured with a flow or volume standard that is traceable to a NIST flow or volume calibration standard. Each O_3 concentration generated by dilution is calculated from:

$$[O_3]'_{OUT} = [O_3]_{OUT}\left(\frac{F_O}{F_O+F_D}\right) \qquad (5)$$

Where:

$[O_3]'_{OUT}$ = diluted O_3 concentration, ppm
FO = flow rate through the O_3 generator, liter/min
FD = diluent air flow rate, liter/min

Note: Additional information on calibration and pollutant standards is provided in Section 12 of Reference 14.

5.0 Frequency of Calibration.

5.1 The frequency of calibration, as well as the number of points necessary to establish the calibration curve, and the frequency of other performance checking will vary by analyzer; however, the minimum frequency, acceptance criteria, and subsequent actions are specified in Appendix D of Reference 14: Measurement Quality Objectives and Validation Templates. The user's quality control program shall provide guidelines for initial establishment of these variables and for subsequent alteration as operational experience is accumulated. Manufacturers of analyzers should include in their instruction/operation manuals information and guidance as to these variables and on other matters of operation, calibration, routine maintenance, and quality control.

6.0 *References.*

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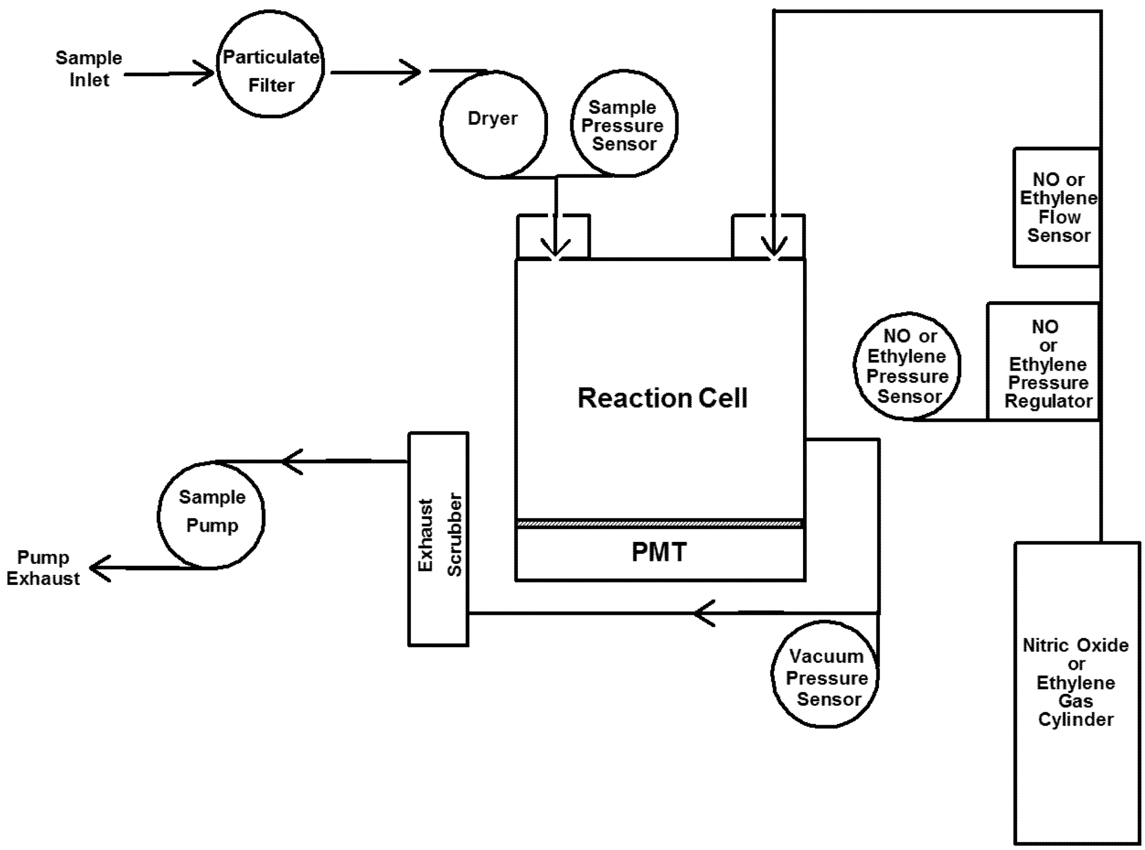

Figure 1. Gas-phase chemiluminescence analyzer schematic diagram, where PMT means photomultiplier tube.

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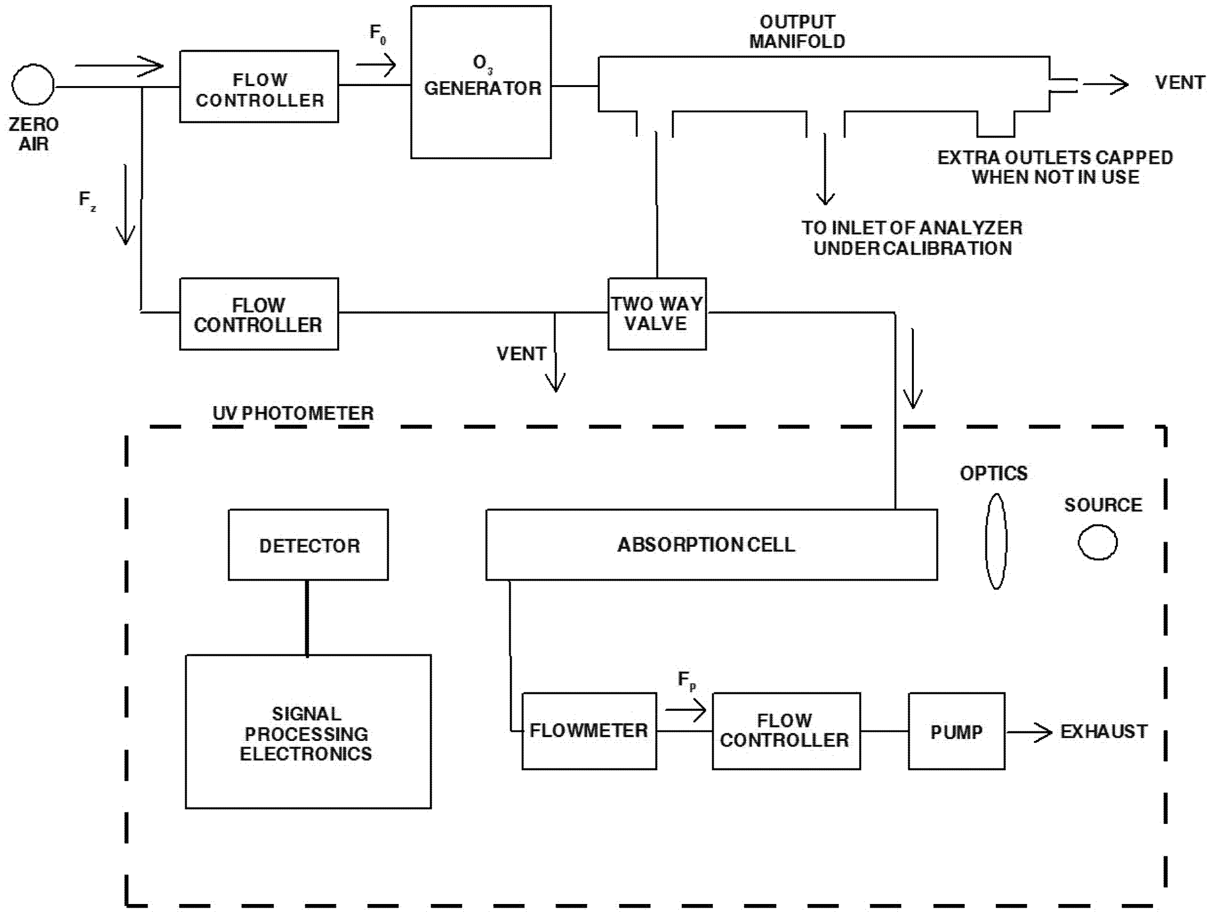

Figure 2. Schematic diagram of a typical UV photometric calibration system.

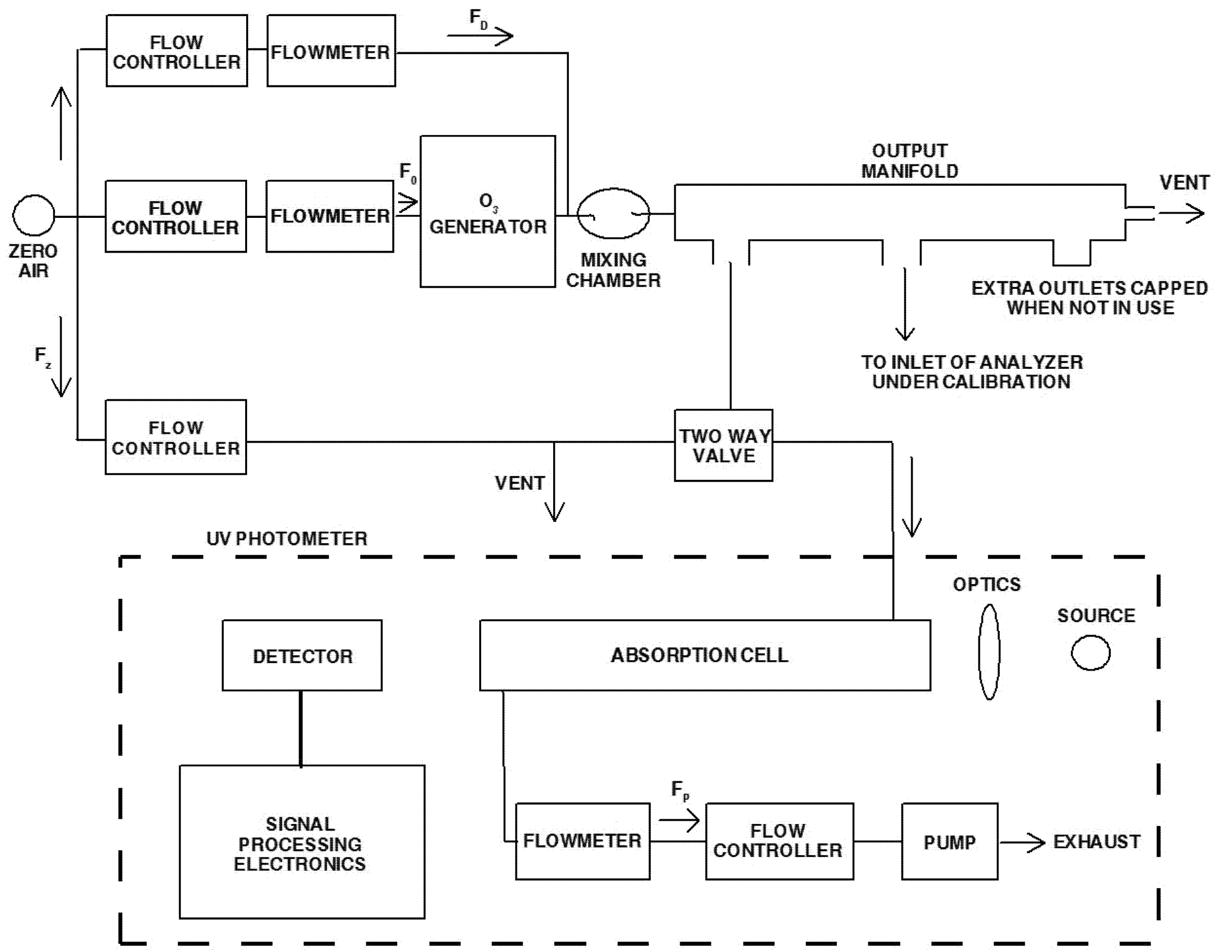

Figure 3. Schematic diagram of a typical UV photometric calibration system (Option 1).

■ 5. Add appendix U to Part 50 to read as follows:

Appendix U to Part 50—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone

1. General

(a) This appendix explains the data handling conventions and computations necessary for determining whether the primary and secondary national ambient air quality standards (NAAQS) for ozone (O_3) specified in § 50.19 are met at an ambient O_3 air quality monitoring site. Data reporting, data handling, and computation procedures to be used in making comparisons between reported O_3 concentrations and the levels of the O_3 NAAQS are specified in the following sections.

(b) Whether to exclude or retain the data affected by exceptional events is determined by the requirements under §§ 50.1, 50.14 and 51.930.

(c) The terms used in this appendix are defined as follows:

8-hour average refers to the moving average of eight consecutive hourly O_3 concentrations measured at a site, as explained in section 3 of this appendix.

Annual fourth-highest daily maximum refers to the fourth highest value measured at a site during a year.

Collocated monitors refers to the instance of two or more O_3 monitors operating at the same physical location.

Daily maximum 8-hour average O_3 concentration refers to the maximum calculated 8-hour average value measured at a site on a particular day, as explained in section 3 of this appendix.

Design value refers to the metric (*i.e.,* statistic) that is used to compare ambient O_3 concentration data measured at a site to the NAAQS in order to determine compliance, as explained in section 4 of this appendix.

Minimum data completeness requirements refer to the amount of data that a site is required to collect in order to make a valid determination that the site is meeting the NAAQS.

Monitor refers to a physical instrument used to measure ambient O_3 concentrations.

O_3 *monitoring season* refers to the span of time within a year when individual states are required to measure ambient O_3 concentrations, as listed in Appendix D to part 58 of this chapter.

Site refers to an ambient O_3 air quality monitoring site.

Site data record refers to the set of hourly O_3 concentration data collected at a site for use in comparisons with the NAAQS.

Year refers to calendar year.

2. Selection of Data for use in Comparisons With the Primary and Secondary Ozone NAAQS

(a) All valid hourly O_3 concentration data collected using a federal reference method specified in Appendix D to this part, or an equivalent method designated in accordance with part 53 of this chapter, meeting all applicable requirements in part 58 of this chapter, and submitted to EPA's Air Quality System (AQS) database or otherwise available to EPA, shall be used in design value calculations.

(b) All design value calculations shall be implemented on a site-level basis. If data are reported to EPA from collocated monitors, those data shall be combined into a single site data record as follows:

(i) The monitoring agency shall designate one monitor as the primary monitor for the site.

(ii) Hourly O_3 concentration data from a secondary monitor shall be substituted into the site data record whenever a valid hourly O_3 concentration is not obtained from the primary monitor. In the event that hourly O_3 concentration data are available for more than one secondary monitor, the hourly concentration values from the secondary monitors shall be averaged and substituted into the site data record.

(c) In certain circumstances, including but not limited to site closures or relocations, data from two nearby sites may be combined into a single site data record for the purpose of calculating a valid design value. The appropriate Regional Administrator may approve such combinations after taking into consideration factors such as distance between sites, spatial and temporal patterns in air quality, local emissions and meteorology, jurisdictional boundaries, and terrain features.

3. Data Reporting and Data Handling Conventions

(a) Hourly average O_3 concentrations shall be reported in parts per million (ppm) to the third decimal place, with additional digits to the right of the third decimal place truncated. Each hour shall be identified using local standard time (LST).

(b) Moving 8-hour averages shall be computed from the hourly O_3 concentration data for each hour of the year and shall be stored in the first, or start, hour of the 8-hour period. An 8-hour average shall be considered valid if at least 6 of the hourly concentrations for the 8-hour period are available. In the event that only 6 or 7 hourly concentrations are available, the 8-hour average shall be computed on the basis of the hours available, using 6 or 7, respectively, as the divisor. In addition, in the event that 5 or fewer hourly concentrations are available, the 8-hour average shall be considered valid if, after substituting zero for the missing hourly concentrations, the resulting 8-hour average is greater than the level of the NAAQS, or equivalently, if the sum of the available hourly concentrations is greater than 0.567 ppm. The 8-hour averages shall be reported to three decimal places, with additional digits to the right of the third decimal place truncated. Hourly O_3 concentrations that have been approved under § 50.14 as having been affected by exceptional events shall be counted as missing or unavailable in the calculation of 8-hour averages.

(c) The daily maximum 8-hour average O_3 concentration for a given day is the highest of the 17 consecutive 8-hour averages beginning with the 8-hour period from 7:00 a.m. to 3:00 p.m. and ending with the 8-hour period from 11:00 p.m. to 7:00 a.m. the following day (*i.e.,* the 8-hour averages for 7:00 a.m. to 11:00 p.m.). Daily maximum 8-hour average O_3 concentrations shall be determined for each day with ambient O_3 monitoring data, including days outside the O_3 monitoring season if those data are available.

(d) A daily maximum 8-hour average O_3 concentration shall be considered valid if valid 8-hour averages are available for at least 13 of the 17 consecutive 8-hour periods starting from 7:00 a.m. to 11:00 p.m. In addition, in the event that fewer than 13 valid 8-hour averages are available, a daily maximum 8-hour average O_3 concentration shall also be considered valid if it is greater than the level of the NAAQS. Hourly O_3 concentrations that have been approved under § 50.14 as having been affected by exceptional events shall be included when determining whether these criteria have been met.

(e) The primary and secondary O_3 design value statistic is the annual fourth-highest daily maximum 8-hour O_3 concentration, averaged over three years, expressed in ppm. The fourth-highest daily maximum 8-hour O_3 concentration for each year shall be determined based only on days meeting the validity criteria in 3(d). The 3-year average shall be computed using the three most recent, consecutive years of ambient O_3 monitoring data. Design values shall be reported in ppm to three decimal places, with additional digits to the right of the third decimal place truncated.

4. Comparisons With the Primary and Secondary Ozone NAAQS

(a) The primary and secondary national ambient air quality standards for O_3 are met at an ambient air quality monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration (*i.e.,* the design value) is less than or equal to 0.070 ppm.

(b) A design value greater than the level of the NAAQS is always considered to be valid. A design value less than or equal to the level of the NAAQS must meet minimum data completeness requirements in order to be considered valid. These requirements are met for a 3-year period at a site if valid daily maximum 8-hour average O_3 concentrations are available for at least 90% of the days within the O_3 monitoring season, on average, for the 3-year period, with a minimum of at least 75% of the days within the O_3 monitoring season in any one year.

(c) When computing whether the minimum data completeness requirements have been met, meteorological or ambient data may be sufficient to demonstrate that meteorological conditions on missing days were not conducive to concentrations above the level of the NAAQS. Missing days assumed less than the level of the NAAQS are counted for the purpose of meeting the minimum data completeness requirements, subject to the approval of the appropriate Regional Administrator.

(d) Comparisons with the primary and secondary O_3 NAAQS are demonstrated by examples 1 and 2 as follows:

EXAMPLE 1—SITE MEETING THE PRIMARY AND SECONDARY O_3 NAAQS

Year	Percent valid days within O_3 monitoring season (Data completeness)	1st highest daily max 8-hour O_3 (ppm)	2nd highest daily max 8-hour O_3 (ppm)	3rd highest daily max 8-hour O_3 (ppm)	4th highest daily max 8-hour O_3 (ppm)	5th highest daily max 8-hour O_3 (ppm)
2014	100	0.082	0.080	0.075	0.069	0.068
2015	96	0.074	0.073	0.065	0.062	0.060
2016	98	0.070	0.069	0.067	0.066	0.060
Average	98				0.065	

As shown in Example 1, this site meets the primary and secondary O_3 NAAQS because the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentrations (*i.e.,* 0.065666 ppm, truncated to 0.065 ppm) is less than or equal to 0.070 ppm. The minimum data completeness requirements are also met (*i.e.,* design value is considered valid) because the average percent of days within the O_3 monitoring season with valid ambient monitoring data is greater than 90%, and no single year has less than 75% data completeness.

EXAMPLE 2—SITE FAILING TO MEET THE PRIMARY AND SECONDARY O3 O_3 NAAQS

Year	Percent valid days within O_3 monitoring season (Data completeness)	1st highest daily max 8-hour O_3 (ppm)	2nd highest daily max 8-hour O_3 (ppm)	3rd highest daily max 8-hour O_3 (ppm)	4th highest daily max 8-hour O_3 (ppm)	5th highest daily max 8-hour O_3 (ppm)
2014	96	0.085	0.080	0.079	0.074	0.072

EXAMPLE 2—SITE FAILING TO MEET THE PRIMARY AND SECONDARY O3 O_3 NAAQS—Continued

Year	Percent valid days within O_3 monitoring season (Data completeness)	1st highest daily max 8-hour O_3 (ppm)	2nd highest daily max 8-hour O_3 (ppm)	3rd highest daily max 8-hour O_3 (ppm)	4th highest daily max 8-hour O_3 (ppm)	5th highest daily max 8-hour O_3 (ppm)
2015	74	0.084	0.083	0.072	0.071	0.068
2016	98	0.083	0.081	0.081	0.075	0.074
Average	89	....	....	....	0.073	

As shown in Example 2, this site fails to meet the primary and secondary O_3 NAAQS because the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentrations (*i.e.,* 0.073333 ppm, truncated to 0.073 ppm) is greater than 0.070 ppm, even though the annual data completeness is less than 75% in one year and the 3-year average data completeness is less than 90% (*i.e.,* design value would not otherwise be considered valid).

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 6. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart I—–Review of New Sources and Modifications

■ 8. Amend § 51.166 by adding paragraph (i)(11) to read asfollows:

§ 51.166 Prevention of significant deterioration of air quality.

* * * * *

(i) * * *

(11) The plan may provide that the requirements of paragraph (k)(1) of this section shall not apply to a permit application for a stationary source or modification with respect to the revised national ambient air quality standards for ozone published on October 26, 2015 if:

(i) The reviewing authority has determined the permit application subject to this section to be complete on or before October 1, 2015. Instead, the requirements in paragraph (k)(1) of this section shall apply with respect to the national ambient air quality standards for ozone in effect at the time the reviewing authority determined the permit application to be complete; or

(ii) The reviewing authority has first published before December 28, 2015 a public notice of a preliminary determination or draft permit for the permit application subject to this section. Instead, the requirements in paragraph (k)(1) of this section shall apply with respect to the national ambient air quality standards for ozone in effect at the time of first publication of a public notice of the preliminary determination or draft permit.

* * * * *

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 8. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 9. Amend § 52.21 by adding paragraph (i)(12) to read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

* * * * *

(i) * * *

(12) The requirements of paragraph (k)(1) of this section shall not apply to a permit application for a stationary source or modification with respect to the revised national ambient air quality standards for ozone published on October 26, 2015 if:

(i) The Administrator has determined the permit application subject to this section to be complete on or before October 1, 2015. Instead, the requirements in paragraph (k)(1) of this section shall apply with respect to the national ambient air quality standards for ozone in effect at the time the Administrator determined the permit application to be complete; or

(ii) The Administrator has first published before December 28, 2015 a public notice of a preliminary determination or draft permit for the permit application subject to this section. Instead, the requirements in paragraph (k)(1) of this section shall apply with respect to the national ambient air quality standards for ozone in effect on the date the Administrator first published a public notice of a preliminary determination or draft permit.

* * * * *

PART 53—AMBIENT AIR MONITORING REFERENCE AND EQUIVALENT METHODS

■ 10. The authority citation for part 53 continues to read as follows:

Authority: Sec. 301(a) of the Clean Air Act (42 U.S.C. 1857g(a)), as amended by sec. 15(c)(2) of Pub. L. 91–604, 84 Stat. 1713, unless otherwise noted.

Subpart A—General Provisions

§ 53.9 [Amended]

■ 11. Amend § 53.9 by removing paragraph (i).

■ 12. Amend § 53.14 by revising paragraph (c) introductory text to read as follows:

§ 53.14 Modification of a reference or equivalent method.

* * * * *

(c) Within 90 calendar days after receiving a report under paragraph (a) of this section, the Administrator will take one or more of the following actions:

* * * * *

Subpart B—Procedures for Testing Performance Characteristics of Automated Methods for SO_2, CO, O_3, and NO_2

■ 13. Amend § 53.23 by revising paragraph (e)(1)(vi) to read as follows:

§ 53.23 Test procedures.

* * * * *

(e) * * *

(1) * * *

(vi) *Precision:* Variation about the mean of repeated measurements of the same pollutant concentration, denoted as the standard deviation expressed as a percentage of the upper range limits.[258]

* * * * *

■ 14. Revise Table B–1 to Subpart B of Part 53 to read as follows:

[258] NO_2 precision in Table B–1 is also changed to percent to agree with the calculation specified in 53.23(e)(10)(vi).

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TABLE B–1 TO SUBPART B OF PART 53—PERFORMANCE LIMIT SPECIFICATIONS FOR AUTOMATED METHODS

Performance parameter	Units [1]	SO_2		O_3		CO		NO_2 (Std. range)	Definitions and test procedures
		Std. range [3]	Lower range [2,3]	Std. range [3]	Lower range [2,3]	Std. range [3]	Lower range [2,3]		
1. Range	ppm	0–0.5	<0.5	0–0.5	<0.5	0–50	<50	0–0.5	Sec. 53.23(a)
2. Noise	ppm	0.001	0.0005	0.0025	0.001	0.2	0.1	0.005	Sec. 53.23(b)
3. Lower detectable limit	ppm	0.002	0.001	0.005	0.002	0.4	0.2	0.010	Sec. 53.23(c)
4. Interference equivalent									
Each interferent	ppm	±0.005	[4] ±0.005	±0.005	±0.005	±1.0	±0.5	±0.02	Sec. 53.23(d)
Total, all interferents	ppm	–	–	–	–	–	–	0.04	Sec. 53.23(d)
5. Zero drift, 12 and 24 hour.	ppm	±0.004	±0.002	±0.004	±0.002	±0.5	±0.3	±0.02	Sec. 53.23(e)
6. Span drift, 24 hour									
20% of upper range limit.	Percent	–	–	–	–	–	–	±20.0	Sec. 53.23(e)
80% of upper range limit.	Percent	±3.0	±3.0	±3.0	±3.0	±2.0	±2.0	±5.0	Sec. 53.23(e)
7. Lag time	Minutes	2	2	2	2	2.0	2.0	20	Sec. 53.23(e)
8. Rise time	Minutes	2	2	2	2	2.0	2.0	15	Sec. 53.23(e)
9. Fall time	Minutes	2	2	2	2	2.0	2.0	15	Sec. 53.23(e)
10. Precision									
20% of upper range limit.		–	–	–	–	–	–		Sec. 53.23(e)
	Percent [5]	2	2	2	2	1.0	1.0	4	Sec. 53.23(e)
80% of upper range limit.		–	–	–	–	–	–		Sec. 53.23(e)
	Percent [5]	2	2	2	2	1.0	1.0	6	Sec. 53.23(e) Sec. 53.23(e)

[1] To convert from parts per million (ppm) to µg/m^3 at 25 °C and 760 mm Hg, multiply by M/0.02447, where M is the molecular weight of the gas. Percent means percent of the upper measurement range limit.

[2] Tests for interference equivalent and lag time do not need to be repeated for any lower range provided the test for the standard range shows that the lower range specification (if applicable) is met for each of these test parameters.

[3] For candidate analyzers having automatic or adaptive time constants or smoothing filters, describe their functional nature, and describe and conduct suitable tests to demonstrate their function aspects and verify that performances for calibration, noise, lag, rise, fall times, and precision are within specifications under all applicable conditions. For candidate analyzers with operator-selectable time constants or smoothing filters, conduct calibration, noise, lag, rise, fall times, and precision tests at the highest and lowest settings that are to be included in the FRM or FEM designation.

[4] For nitric oxide interference for the SO_2 UVF method, interference equivalent is ±0.0003 ppm for the lower range.

[5] Standard deviation expressed as percent of the URL.

Table B-3 to Subpart B of Part 53—Interferent Test Concentration,[1] Parts per Million

Pollutant	Analyzer type	Hydrochloric acid	Ammonia	Hydrogen sulfide	Sulfur dioxide	Nitrogen dioxide	Nitric oxide	Carbon dioxide	Ethylene	Ozone	m-Xylene	Water vapor	Carbon monoxide	Methane	Ethane	Naphthalene
SO_2	Ultraviolet fluorescence			[5] 0.1	[4] 0.14	0.5	0.5			0.5	0.2	20,000				0.05
SO_2	Flame photometric			0.01	[4] 0.14			750				[3] 20,000	50			
SO_2	Gas chromatography			0.1	[4] 0.14			750				[3] 20,000	50			
SO_2	Spectrophotometric -wet chemical (pararosanaline)	0.2	0.1	0.1	[4] 0.14	0.5		750		0.5						
SO_2	Electrochemical	0.2	0.1	0.1	[4] 0.14	0.5	0.5		0.2	0.5		[3] 20,000				
SO_2	Conductivity	0.2	0.1		[4] 0.14	0.5		750								
SO_2	Spectrophotometric -gas phase, including DOAS				[4] 0.14	0.5				0.5	0.2					
O_3	Ethylene chemiluminescene			0.1				750		[4] 0.08		20,000				
O_3	NO-chemiluminescene			0.1		0.5		750		[4] 0.08		20,000				
O_3	Electrochemical		[3] 0.1		0.5	0.5				[4] 0.08						
O_3	Spectrophotometric -wet chemical (potassium iodide)		[3] 0.1		0.5	0.5	0.5			[4] 0.08						

O_3	Spectrophotometric -gas phase, including ultraviolet absorption and DOAS				0.5	0.5	0.5			[4] 0.08	0.02	20,000				
CO	Non-dispersive Infrared							750				20,000	[4] 10			
CO	Gas chromatography with flame ionization detector											20,000	[4] 10		0.5	
CO	Electrochemical						0.5		0.2			20,000	[4] 10			
CO	Catalytic combustion-thermal detection		0.1					750	0.2			20,000	[4] 10	5.0	0.5	
CO	IR fluorescence							750				20,000	[4] 10		0.5	
CO	Mercury replacement-UV photometric								0.2				[4] 10		0.5	
NO_2	Chemiluminescent		[3] 0.1		0.5	[4] 0.1	0.5					20,000				
NO_2	Spectrophotometric -wet chemical (azo-dye reaction)				0.5	[4] 0.1	0.5	750		0.5						
NO_2	Electrochemical	0.2	[3] 0.1		0.5	[4] 0.1	0.5	750		0.5		20,000	50			
NO_2	Spectrophotometric -gas phase		[3] 0.1		0.5	[4] 0.1	0.5			0.5		20,000	50			

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[1] Concentrations of interferents listed must be prepared and controlled to ±10 percent of the stated value.
[2] Analyzer types not listed will be considered by the Administrator as special cases.
[3] Do not mix with the pollutant.
[4] Concentration of pollutant used for test. These pollutant concentrations must be prepared to ±10 percent of the stated value.
[5] If candidate method utilizes an elevated-temperature scrubber for removal of aromatic hydrocarbons, perform this interference test.
[6] If naphthalene test concentration cannot be accurately quantified, remove the scrubber, use a test concentration that causes a full scale response, reattach the scrubber, and evaluate response for interference.

CALCULATION OF ZERO DRIFT, SPAN DRIFT, AND PRECISION

Applicant________________________ Date________________

Analyzer________________________ Pollutant________________

TEST PARAMETERS		CALCULATIONS	TEST DAY (n)														
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ZERO DRIFT	12 HOUR	$12ZD = C_{max} - C_{min}$															
	24 HOUR	$Z = (L_1 + L_2)/2$															
		$24ZD = Z_n - Z_{n-1}$															
		$24ZD = Z'_n - Z'_{n-1}$															
SPAN DRIFT	24 HOUR	$S_n = \frac{1}{6}\sum_{i=7}^{12} P_i$															
		$SD_n = \frac{S_n - S_{n-1}}{S_{n-1}} \times 100\%$															
		$SD_n = \frac{S_n - S'_{n-1}}{S'_{n-1}} \times 100\%$															
PREC-ISION	20% URL (P_{20})	P_{20} = % STANDARD DEVIATION OF ($P_1 \ldots P_6$)															
	80% URL (P_{80})	P_{80} = % STANDARD DEVIATION OF ($P_7 \ldots P_{12}$)															

Figure B-5. Form for calculating zero drift, span drift, and precision (§ 53.23(e)).

* * * * *

Subpart C—Procedures for Determining Comparability between Candidate Methods and Reference Methods

■ 17. Amend § 53.32 by revising paragraph (g)(1)(iii) to read as follows:

§ 53.32 Test procedures for methods for SO_2, CO, O_3, and NO_2.

* * * * *

(g) * * *

(1) * * *

(iii) The measurements shall be made in the sequence specified in table C–2 of this subpart.

* * * * *

Figure E–2 to Subpart E of Part 53 [Removed]

■ 18. Amend subpart E by removing figure E–2 to subpart E of part 53.

PART 58—AMBIENT AIR QUALITY SURVEILLANCE

■ 19. The authority citation for part 58 continues to read as follows:

Authority: 42 U.S.C. 7403, 7405, 7410, 7414, 7601, 7611, 7614, and 7619.

Subpart B—Monitoring Network

■ 20. Amend § 58.10 by adding paragraphs (a)(9) through (11) to read as follows:

§ 58.10 Annual monitoring network plan and periodic network assessment.

(a) * * *

(9) The annual monitoring network plan shall provide for the required O_3 sites to be operating on the first day of the applicable required O_3 monitoring season in effect on January 1, 2017 as listed in Table D–3 of appendix D of this part.

(10) A plan for making Photochemical Assessment Monitoring Stations (PAMS) measurements, if applicable, in accordance with the requirements of appendix D paragraph 5(a) of this part shall be submitted to the EPA Regional Administrator no later than July 1, 2018. The plan shall provide for the required PAMS measurements to begin by June 1, 2019.

(11) An Enhanced Monitoring Plan for O_3, if applicable, in accordance with the requirements of appendix D paragraph 5(h) of this part shall be submitted to the EPA Regional Administrator no later than October 1, 2019 or two years following the effective date of a designation to a classification of Moderate or above O_3 nonattainment, whichever is later.

* * * * *

■ 21. Section § 58.11 is amended by revising paragraph (c) to read as follows:

§ 58.11 Network technical requirements.

* * * * *

(c) State and local governments must follow the network design criteria contained in appendix D to this part in designing and maintaining the SLAMS stations. The final network design and all changes in design are subject to approval of the Regional Administrator. NCore and STN network design and changes are also subject to approval of the Administrator. Changes in SPM stations do not require approvals, but a change in the designation of a monitoring site from SLAMS to SPM requires approval of the Regional Administrator.

* * * * *

■ 22. Amend § 58.13 by adding paragraphs (g) and (h) to read as follows:

§ 58.13 Monitoring network completion.

* * * * *

(g) The O_3 monitors required under appendix D, section 4.1 of this part must operate on the first day of the applicable required O_3 monitoring season in effect January 1, 2017.

(h) The Photochemical Assessment Monitoring sites required under 40 CFR part 58 Appendix D, section 5(a) must be physically established and operating under all of the requirements of this part, including the requirements of appendix A, C, D, and E of this part, no later than June 1, 2019.

Subpart F—Air Quality Index Reporting

■ 23. Amend § 58.50 by revising paragraph (c) to read as follows:

§ 58.50 Index reporting.

* * * * *

(c) The population of a metropolitan statistical area for purposes of index reporting is the latest available U.S. census population.

Subpart G—Federal Monitoring

■ 24. Amend appendix D to part 58, under section 4, by revising section 4.1(i) and table D–3 to appendix D of part 58, and by revising section 5 to read as follows:

Appendix D to part 58—Network Design Criteria for Ambient Air Quality Monitoring

* * * * *

4. Pollutant-Specific Design Criteria for SLAMS Sites

* * * * *

4.1 * * *

(i) Ozone monitoring is required at SLAMS monitoring sites only during the seasons of the year that are conducive to O_3 formation (*i.e.,* ''ozone season'') as described below in Table D–3 of this appendix. These O_3 seasons are also identified in the AQS files on a state-by-state basis. Deviations from the O_3 monitoring season must be approved by the EPA Regional Administrator. These requests will be reviewed by Regional Administrators taking into consideration, at a minimum, the frequency of out-of-season O_3 NAAQS exceedances, as well as occurrences of the Moderate air quality index level, regional consistency, and logistical issues such as site access. Any deviations based on the Regional Administrator's waiver of requirements must be described in the annual monitoring network plan and updated in AQS. Changes to the O_3 monitoring season requirements in Table D–3 revoke all previously approved Regional Administrator waivers. Requests for monitoring season deviations must be accompanied by relevant supporting information. Information on how to analyze O_3 data to support a change to the O_3 season in support of the 8-hour standard for the entire network in a specific state can be found in reference 8 to this appendix. Ozone monitors at NCore stations are required to be operated year-round (January to December).

TABLE D–3 [1] TO APPENDIX D OF PART 58. OZONE MONITORING SEASON BY STATE

State	Begin Month	End Month
Alabama	March	October.
Alaska	April	October.
Arizona	January	December.
Arkansas	March	November.
California	January	December.
Colorado	January	December.
Connecticut	March	September.
Delaware	March	October.
District of Columbia	March	October.

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TABLE D–3[1] TO APPENDIX D OF PART 58. OZONE MONITORING SEASON BY STATE—Continued

State	Begin Month	End Month
Florida	January	December.
Georgia	March	October.
Hawaii	January	December.
Idaho	April	September.
Illinois	March	October.
Indiana	March	October.
Iowa	March	October.
Kansas	March	October.
Kentucky	March	October.
Louisiana (Northern) AQCR 019, 022	March	October.
Louisiana (Southern) AQCR 106	January	December.
Maine	April	September.
Maryland	March	October.
Massachusetts	March	September.
Michigan	March	October.
Minnesota	March	October.
Mississippi	March	October.
Missouri	March	October.
Montana	April	September.
Nebraska	March	October.
Nevada	January	December.
New Hampshire	March	September.
New Jersey	March	October.
New Mexico	January	December.
New York	March	October.
North Carolina	March	October.
North Dakota	March	September.
Ohio	March	October.
Oklahoma	March	November.
Oregon	May	September.
Pennsylvania	March	October.
Puerto Rico	January	December.
Rhode Island	March	September.
South Carolina	March	October.
South Dakota	March	October.
Tennessee	March	October.
Texas (Northern) AQCR 022, 210, 211, 212, 215, 217, 218	March	November.
Texas (Southern) AQCR 106, 153, 213, 214, 216	January	December.
Utah	January	December.
Vermont	April	September.
Virginia	March	October.
Washington	May	September.
West Virginia	March	October.
Wisconsin	March	October 15.
Wyoming	January	September.
American Samoa	January	December.
Guam	January	December.
Virgin Islands	January	December.

[1] The required O_3 monitoring season for NCore stations is January through December.

* * * * *

5. Network Design for Photochemical Assessment Monitoring Stations (PAMS) and Enhanced Ozone Monitoring

(a) State and local monitoring agencies are required to collect and report PAMS measurements at each NCore site required under paragraph 3(a) of this appendix located in a CBSA with a population of 1,000,000 or more, based on the latest available census figures.

(b) PAMS measurements include:

(1) Hourly averaged speciated volatile organic compounds (VOCs);

(2) Three 8-hour averaged carbonyl samples per day on a 1 in 3 day schedule, or hourly averaged formaldehyde;

(3) Hourly averaged O_3;

(4) Hourly averaged nitrogen oxide (NO), true nitrogen dioxide (NO_2), and total reactive nitrogen (NO_y);

(5) Hourly averaged ambient temperature;

(6) Hourly vector-averaged wind direction;

(7) Hourly vector-averaged wind speed;

(8) Hourly average atmospheric pressure;

(9) Hourly averaged relative humidity;

(10) Hourly precipitation;

(11) Hourly averaged mixing-height;

(12) Hourly averaged solar radiation; and

(13) Hourly averaged ultraviolet radiation.

(c) The EPA Regional Administrator may grant a waiver to allow the collection of required PAMS measurements at an alternative location where the monitoring agency can demonstrate that the alternative location will provide representative data useful for regional or national scale modeling and the tracking of trends in O_3 precursors. The alternative location can be outside of the CBSA or outside of the monitoring agencies jurisdiction. In cases where the alternative location crosses jurisdictions the waiver will be contingent on the monitoring agency responsible for the alternative location including the required PAMS measurements in their annual monitoring plan required under § 58.10 and continued successful collection of PAMS measurements at the alternative location. This waiver can be revoked in cases where the Regional Administrator determines the PAMS measurements are not being collected at the alternate location in compliance with paragraph (b) of this section.

(d) The EPA Regional Administrator may grant a waiver to allow speciated VOC measurements to be made as three 8-hour averages on every third day during the PAMS

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season as an alternative to 1-hour average speciated VOC measurements in cases where the primary VOC compounds are not well measured using continuous technology due to low detectability of the primary VOC compounds or for logistical and other programmatic constraints.

(e) The EPA Regional Administrator may grant a waiver to allow representative meteorological data from nearby monitoring stations to be used to meet the meteorological requirements in paragraph 5(b) where the monitoring agency can demonstrate the data is collected in a manner consistent with EPA quality assurance requirements for these measurements.

(f) The EPA Regional Administrator may grant a waiver from the requirement to collect PAMS measurements in locations where CBSA-wide O_3 design values are equal to or less than 85% of the 8-hour O_3 NAAQS and where the location is not considered by the Regional Administrator to be an important upwind or downwind location for other O_3 nonattainment areas.

(g) At a minimum, the monitoring agency shall collect the required PAMS measurements during the months of June, July, and August.

(h) States with Moderate and above 8-hour O_3 nonattainment areas and states in the Ozone Transport Region as defined in 40 CFR 51.900 shall develop and implement an Enhanced Monitoring Plan (EMP) detailing enhanced O_3 and O_3 precursor monitoring activities to be performed. The EMP shall be submitted to the EPA Regional Administrator no later than October 1, 2019 or two years following the effective date of a designation to a classification of Moderate or above O_3 nonattainment, whichever is later. At a minimum, the EMP shall be reassessed and approved as part of the 5-year network assessments required under 40 CFR 58.10(d). The EMP will include monitoring activities deemed important to understanding the O_3 problems in the state. Such activities may include, but are not limited to, the following:

(1) Additional O_3 monitors beyond the minimally required under paragraph 4.1 of this appendix,

(2) Additional NO_X or NO_y monitors beyond those required under 4.3 of this appendix,

(3) Additional speciated VOC measurements including data gathered during different periods other than required under paragraph 5(g) of this appendix, or locations other than those required under paragraph 5(a) of this appendix, and

(4) Enhanced upper air measurements of meteorology or pollution concentrations.

* * * * *

■ 25. Appendix G of Part 58 is amended by revising table 2 to read as follows:

Appendix G to Part 58—Uniform Air Quality Index (AQI) and Daily Reporting

* * * * *

TABLE 2—BREAKPOINTS FOR THE AQI

These breakpoints							Equal these AQI's	
O_3 (ppm) 8-hour	O_3 (ppm) 1-hour[1]	$PM_{2.5}$ (µg/m^3) 24-hour	PM_{10} (µg/m^3) 24-hour	CO (ppm) 8-hour	SO_2 (ppb) 1-hour	NO_2 (ppb) 1-hour	AQI	Category
0.000–0.054	—	0.0—12.0	0–54	0.0–4.4	0–35	0–53	0–50	Good.
0.055–0.070	—	12.1—35.4	55–154	4.5–9.4	36–75	54–100	51–100	Moderate.
0.071–0.085	0.125–0.164	35.5—55.4	155–254	9.5–12.4	76–185	101–360	101–150	Unhealthy for Sensitive Groups.
0.086–0.105	0.165–0.204	[3] 55.5—150.4	255–354	12.5–15.4	[4] 186–304	361–649	151–200	Unhealthy.
0.106–0.200	0.205–0.404	[3] 150.5—250.4	355–424	15.5–30.4	[4] 305–604	650–1249	201–300	Very Unhealthy.
0.201-([2])	0.405–0.504	[3] 250.5—350.4	425–504	30.5–40.4	[4] 605–804	1250–1649	301–400	Hazardous.
([2])	0.505–0.604	[3] 350.5—500.4	505–604	40.5–50.4	[4] 805–1004	1650–2049	401–500	

[1] Areas are generally required to report the AQI based on 8-hour ozone values. However, there are a small number of areas where an AQI based on 1-hour ozone values would be more precautionary. In these cases, in addition to calculating the 8-hour ozone index value, the 1-hour ozone index value may be calculated, and the maximum of the two values reported.

[2] 8-hour O_3 values do not define higher AQI values (>301). AQI values > 301 are calculated with 1-hour O_3 concentrations.

[3] If a different SHL for $PM_{2.5}$ is promulgated, these numbers will change accordingly.

[4] 1-hr SO_2 values do not define higher AQI values (≥200). AQI values of 200 or greater are calculated with 24-hour SO_2 concentration.

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§ 721.63(a)(1), (a)(2)(i), (a)(3), when determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) engineering control measures (*e.g.,* enclosure or confinement of the operation, general and local ventilation) or administrative control measures (*e.g.,* workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible, (b)(concentration set 1.0%), and (c).

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (e)(concentration set 1.0%), (f), (g)(1)(vi), (adrenal effects), (liver effects), (g)(2)(i), (ii), (iii), (v), and (g)(5).

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(t) and (y)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers and processors of this substance.

(2) *Limitations or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

(3) *Determining whether a specific use is subject to this section.* The provisions of § 721.1725(b)(1) apply to paragraph (a)(2)(iii) of this section.

§ 721.11094 Poly(oxy-1,2-ethanediyl),alpha-(2-benzoyl)-omega-[(2-benzoylbenzoyl)oxy]-.

(a) Chemical substance and significant new uses subject to reporting. (1) The chemical substance identified as poly(oxy-1,2-ethanediyl),alpha-(2-benzoyl)-omega-[(2-benzoylbenzoyl)oxy]- (PMN P–17–261; CAS No. 1246194–73–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been reacted (cured).

(2) The significant new uses are:

(i) Protection in the workplace. Requirements as specified in § 721.63(a)(1), (a)(2)(i), (a)(3), when determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) engineering control measures (*e.g.,* enclosure or confinement of the operation, general and local ventilation) or administrative control measures (*e.g.,* workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible, (b)(concentration set at 1.0%), and (c).

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (e) (concentration set at 1.0%), (f), (g)(1)(irritation), (photosensitization), (g)(2)(i), (ii), (iii), (v), and (g)(5).

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f) and (q).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers and processors of this substance.

(2) *Limitations or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

(3) *Determining whether a specific use is subject to this section.* The provisions of § 721.1725(b)(1) apply to paragraph (a)(2)(iii) of this section.

[FR Doc. 2019–19667 Filed 9–17–19; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2018–0706; FRL–9998–72–Region 6]

Air Plan Approval; New Mexico; Infrastructure for the 2015 Ozone National Ambient Air Quality Standards and Repeal of State Regulations for Total Suspended Particulate

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is approving State Implementation Plan (SIP) infrastructure certifications from the State of New Mexico and Albuquerque-Bernalillo County to address CAA section 110(a)(1) and (2) requirements for the 2015 ozone (O_3) National Ambient Air Quality Standards (NAAQS). The submittals address how the existing SIP provides for the implementation, maintenance, and enforcement of the 2015 O_3 NAAQS (infrastructure SIP or i-SIP). The i-SIP ensures that the New Mexico SIP is adequate to meet the state's responsibilities under the CAA for this NAAQS. The EPA is also approving a SIP revision for the repeal of the New Mexico Ambient Air Quality Standards (NMAAQS) for total suspended particulate (TSP) in the New Mexico regulations incorporated into the SIP.

DATES: This rule is effective on October 18, 2019.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–R06–OAR–2018–0706. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov* or in hard copy at the EPA Region 6 Office, 1201 Elm Street, Suite 500, Dallas, Texas 75270.

FOR FURTHER INFORMATION CONTACT: Ms. Karolina Ruan Lei, EPA Region 6 Office, 1201 Elm Street, Suite 500, Dallas, TX 75270, (214) 665–7346, *ruan-lei.karolina@epa.gov.* To inspect the hard copy materials, please schedule an appointment with Ms. Karolina Ruan Lei or Mr. Bill Deese at (214) 665–7253.

SUPPLEMENTARY INFORMATION: Throughout this document ''we,'' ''us,'' and ''our'' means the EPA.

I. Background

The background for this action is discussed in detail in our proposal published on April 18, 2019 (84 FR 16226). In that notice we proposed to approve the November 1, 2018, and September 24, 2018, i-SIP certifications submitted by the State of New Mexico and Albuquerque-Bernalillo County, respectively. The November 1, 2018, and September 24, 2018, submittals addressed the implementation, maintenance, and enforcement of the 2015 O_3 NAAQS in New Mexico, including two of the four interstate transport requirements (CAA section 110(a)(2)(D)(i)(II)). We also proposed to approve a SIP revision submitted on November 16, 2018, by the State of New Mexico that pertains to the repeal of the air quality standards for TSP in New Mexico. The November 16, 2018, submital included a demonstration that the repeal of the TSP NMAAQS will not interfere with the attainment and maintenance of the NAAQS or any other CAA requirement.

We received comments on the April 18, 2019, proposal from two commenters on the infrastructure portion of the action. One commenter

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was anonymous and submitted adverse comments on several elements of the New Mexico i-SIPs. The other commenter was the City of Albuquerque Environmental Health Department (EHD), who submitted a comment letter to correct certain statements made in the proposal. We did not receive any comments regarding the repeal of the TSP NMAAQS. Our response to the comments is provided in the section below.

II. Response to Comments

Comment: The commenter stated that the EPA should disapprove the current infrastructure SIP as it relates to prevention of significant deterioration (PSD) elements. The current approved version of the New Mexico regulation does not require ammonia as a precursor to fine particulate matter ($PM_{2.5}$) evaluations. The commenter stated that the EPA claims the State and County have a ''comprehensive'' program, but the approved regulation does not include ammonia as a precursor. The commenter stated that New Mexico must update its permitting programs for both the State and the counties.

Response: The EPA disagrees with the comment. The EPA's minimum requirements for a state PSD program at 40 CFR 51.166 do not regulate ammonia as either a precursor or a presumed precursor for $PM_{2.5}$ for PSD permitting. Regulated precursors for $PM_{2.5}$ for PSD permitting are defined at 40 CFR 51.166(b)(49)(i)(*b*)(*2*) and (*3*) as sulfur dioxide and nitrogen oxides, respectively.[1] The State of New Mexico and Albuquerque-Bernalillo County PSD programs were SIP-approved for the regulation of $PM_{2.5}$ and its precursors on January 22, 2013, and September 19, 2012, respectively (78 FR 4339 and 77 FR 58032). The New Mexico State and County SIP-approved PSD programs are comprehensive PSD programs that cover all regulated pollutants, including $PM_{2.5}$ and its applicable precursors.

Comment: The commenter stated that New Mexico's permitting program requires ambient air quality modeling to be performed ''as specified in EPA's Guideline on Air Quality Models (EPA–450/2–78–027R, July 1986), its revisions, or any superseding document, and approved by the Department.'' The commenter stated that this text in the regulation restricts the State from requiring the most up-to-date modeling as required in 40 CFR part 52, Appendix W, which is not a ''superseding document'', as it is a regulation promulgated by the EPA and not a document.

The commenter also stated that the State's rule appears to give the State inappropriate director's discretion in the use of what air quality modeling is used as the language ''and approved by the department'' appears to allow the department to disregard EPA-required modeling if the department does not approve of it. The commenter stated that director's discretion was outlawed by the Courts in *NRDC* v. *EPA* in 2013 and was affirmed by the EPA in its startup, shutdown, and malfunction SIP call. The commenter additionally stated that this modeling problem should also require the EPA to disapprove Element K as well, since that also has to do with modeling.

Response: The EPA disagrees with the commenter that the text in the New Mexico regulation, which the commenter cited from 20.2.74.305 of the New Mexico Administrative Code (NMAC), restricts the State from requiring the most up-to-date modeling. The EPA notes that the commenter likely meant to refer to 40 CFR part 51 rather than 40 CFR part 52 as there is no Appendix W in 40 CFR part 52, and the EPA's *Guideline on Air Quality Models* is codified at 40 CFR part 51, Appendix W.

The general definition of the term ''document'' can mean any written, printed, or electronic material that provides information or conveys thoughts or ideas. Any regulation in the CFR is considered a document. The EPA's *Guideline on Air Quality Models* (40 CFR part 51, Appendix W) also refers to itself as a document at several instances throughout its text. The most recent version of the *Guideline on Air Quality Models* is therefore a ''superseding document'' to the July 1986 *Guideline on Air Quality Models* cited in the New Mexico regulations at 20.2.74.305 NMAC.

Additionally, the text in the New Mexico regulations at 20.2.74.305 NMAC also includes any ''revisions'' to the EPA's *Guideline on Air Quality Models.* The January 17, 2017, final rule for the most recent update to Appendix W is titled ''Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter'' and contains a description of the action in the summary, which states that ''[i]n this action, the Environmental Protection Agency (EPA) promulgates revisions to the *Guideline on Air Quality Models*'' (82 FR 5182). The January 17, 2017, final rule also describes in the background section the past revisions of the *Guideline on Air Quality Models* (*Id.*). Therefore, the most recent version of the *Guideline on Air Quality Models* is clearly a ''revision'' to older versions, including the July 1986 version cited in the New Mexico regulation, of the EPA's *Guideline on Air Quality Models.*

The EPA also disagrees with the commenter that the provisions at 20.2.74.305 NMAC provide inappropriate director's discretion to the State of New Mexico. This provision clearly requires that modeling be conducted pursuant to the latest version of the EPA's *Guideline on Air Quality Models.* According to 20.2.74.305 NMAC, ''[a]ny substitution or modification of a model must be approved by the Department'', and ''[n]otification shall be given by the Department of such a substitution or modification and the opportunity for public comment provided for in fulfilling the public notice requirements in subsection B of 20.2.74.400 NMAC''. Additionally, 20.2.74.305 NMAC states that the New Mexico Environment Department (NMED) ''will seek EPA approval of such substitutions or modifications''. The provisions at 20.2.74.305 NMAC, the EPA's regulations at 40 CFR 51.166(l) and the *Guideline on Air Quality Models* itself provide that alternative models, modeling scenarios, or model substitutions may be used if approved by the EPA. The New Mexico rule requires an additional approval from the state air director in addition to the EPA before an applicant can use such an alternative model or model substitution for permitting.

The New Mexico regulations at 20.2.74.305 NMAC, therefore, do not restrict the State from requiring the most recent modeling for permitting as required by 40 CFR 51.166(l) nor do they provide inappropriate director's discretion to the State of New Mexico.

Comment: The commenter asked, with respect to adequate funding, whether the EPA has done a full accounting of the department's finances. The commenter also asked how the EPA can be sure that New Mexico is collecting the correct amount in fees from major title V sources to adequately fund the department and stated that there is no accounting or financial evaluation in the docket that proves

[1] It should also be noted that 40 CFR 51.166(b)(49)(i)(*b*)(*3*) provides that a state may overcome the presumption that nitrogen oxides (NO_X) is a regulated precursor if it demonstrates NO_X emissions from sources in a particular area do not significantly contribute to that area's ambient $PM_{2.5}$ concentrations. The PSD requirements also include a presumption that volatile organic compounds are not precursors to $PM_{2.5}$ in any attainment or unclassifiable area unless found to be a significant contributor to that area's ambient $PM_{2.5}$ concentrations. *See* 40 CFR 51.166(b)(49)(i)(*b*)(*4*).

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New Mexico or the County is adequately funded. The commenter also asked if they are supposed to take the State's word at face value.

Response: A ''full accounting of the NMED's finances'' is not required. Section 110(a)(2) does not require a specific quantitative metric or methodology for determining adequate resources. Section 110(a)(2)(E) requires that the state provide necessary assurances that the state will have adequate funding under state law to carry out the SIP. As mentioned in our TSD for the proposal, to address adequate funding, the NMED and the EHD have the resources necessary to carry out the SIP, which are provided through general funds, permit fees, and the CAA section 103 and 105 grant processes. NMSA 1978, § 74–2–5.1(F) provides the NMED and the EHD with the power to accept, receive and administer grants or other funds or gifts from public and private agencies, including the federal government, or from any person. NMSA 1978, § 74–2–7 authorizes and requires the State and County to adopt regulations to include for the collection of permit fees.

The State of New Mexico's Permit Fee System implements a fee system for all preconstruction air permits issued by the NMED and can be found at 20.2.75 NMAC, *Construction Permit Fees.* The provisions in 20.2.75 NMAC were most recently approved by the EPA on March 29, 2012 (77 FR 18923). In the March 29, 2012, final rule, the EPA found that the rule and revisions to 20.2.75 NMAC met the applicable fee-related requirements in section 110(a)(2) of the CAA (77 FR 18923). Under the provisions of 20.2.75 NMAC, the NMED assesses fees when an owner or operator applies for a notice of intent, a permit to construct or modify a source, or a revision to a construction permit. Additionally, annual fees are assessed for sources that have been issued a permit under 20.2.72 NMAC, *Construction Permits.*

Albuquerque-Bernalillo County's provisions for permit fees are codified in 20.11.2 NMAC, *Fees,* and 20.11.41, *Construction Permits,* which were most recently approved by the EPA on May 24, 2012, and June 29, 2017, respectively (77 FR 30900 and 82 FR 29421). The EPA found that the submitted rules and revisions to 20.11.2 NMAC met the applicable fee-related requirements of section 110(a)(2) of the CAA (76 FR 68385, November 4, 2011; 77 FR 30900, May 24, 2012). Under the provisions of 20.11.2 NMAC, the EHD assesses fees when an owner or operator applies for an air permit, air permit renewal, or air permit amendment. Annual fees are also assessed for sources with existing source registrations or permits.

The State of New Mexico and Albuquerque-Bernalillo County each concluded in their i-SIP submittals that they do not anticipate a need for additional resources to implement their respective plans for the 2015 O_3 NAAQS beyond those which have been utilized for the preparation of said plans, plan revisions submitted to the EPA, and other current programmatic demands.

Additionally, section 110(a)(2)(L) requires SIPs to require each major stationary source to pay permitting fees to the permitting authority to cover the cost of reviewing, approving, implementing and enforcing a permit. Section 110(a)(2) falls under title I of the CAA and governs the implementation, maintenance, and enforcement of the NAAQS, in this instance 2015 O_3, through the federally approved SIP. Section 110 and 40 CFR part 51 also provide mechanisms for programmatic remedies with respect to the SIP. Furthermore, title I addresses minor and major new source review SIP preconstruction permits. The title V program, by contrast, governs operating permits and is addressed by CAA sections 502 through 507. Any evaluation of the title V program and any consequent programmatic remedies must be done pursuant to CAA section 502 and 40 CFR part 70. The scope of this action is limited to determining whether the New Mexico SIP meets certain infrastructure requirements of CAA 110(a)(2) with respect to the 2015 O_3 NAAQS. The State of New Mexico and Albuquerque-Bernalillo County's title V programs are not part of the New Mexico SIP but were approved by the EPA on November 26, 1996 (61 FR 60032). Title V fees are separate from title I fees. As mentioned earlier in this action, title V is subject to evaluation under different statutory and regulatory mechanisms provided for outside the SIP parameters for evaluation under CAA section 110 and 40 CFR part 51. Therefore, the part of the comment that questions whether New Mexico collected the correct amount in fees from major title V sources (Element L) to adequately fund the department is irrelevant to the approval of Element E.

As described in our proposal, TSD, and previously in this response, the EPA's evaluation and approval of adequate resources for the State of New Mexico and Albuquerque-Bernalillo County are based upon various sources of funding, state statutes and rules pursuant to section 110(a)(2). The EPA has not identified sufficient information to support the necessary finding for disapproval with regard to adequate funding. Also, the commenter has not identified any flaws or specific program deficiencies in the State's or County's accounting or fee system, or description of why we would question such. The EPA noted no significant deficiencies, thus indicating that both the State of New Mexico and Albuquerque-Bernalillo County have sufficient resources to implement their respective SIPs. Therefore, the EPA is approving Element E for the State of New Mexico and Albuquerque-Bernalillo County for meeting infrastructure requirements for the 2015 O_3 NAAQS.

Comment: The commenter stated that in Table 1 of the proposed action, the EPA notes that Element J as it pertains to visibility is ''not germane to infrastructure SIPs''. The commenter stated that this statement is incorrect as Element J is a necessary element that needs to be addressed in each and every SIP.

Response: The EPA disagrees with the commenter that the visibility sub-element of Element J needs to be addressed in these infrastructure SIPs from the State of New Mexico and Albuquerque-Bernalillo County for the 2015 O_3 NAAQS. Under 40 CFR part 51 subpart P, implementing the visibility requirements of CAA title I, part C, states are subject to requirements for reasonably attributable visibility impairment, new source review for possible impacts on air quality related values in Class I areas, and regional haze planning. These include timeframes for SIP submittals related to visibility requirements. *See, e.g.,* 40 CFR 51.308(b) (establishing a deadline for initial SIPs to meet regional haze requirements of December 17, 2007). As the EPA recognized in the 2013 Infrastructure SIP Guidance, generally speaking, when the EPA establishes or revises a NAAQS, the visibility requirements under part C of title I of the Clean Air Act do not change. *See* Guidance at pages 54–55.[2] There are no new visibility protection requirements under part C as a result of the revised NAAQS here. Therefore, there are no newly applicable visibility protection obligations pursuant to Element J applicable in or to New Mexico, and this sub-element is therefore not being addressed in this action. We note that the State of New Mexico and Albuquerque-Bernalillo County each currently have a fully approved SIP under subpart P, addressing best

[2] ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)''. Memorandum from Stephen D. Page, U.S. EPA, Office of Air Quality Planning and Standards. September 13, 2013.

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available retrofit technology (BART) and reasonable progress requirements as part of their long-term strategy for improving visibility during the first planning period. For the State of New Mexico, see 77 FR 70693 (November 27, 2012) and 79 FR 60985 (October 9, 2014) for the final approval of the State's regional haze SIP, and see 82 FR 27127 (June 14, 2017) for the final approval of the State's five-year progress report. For Albuquerque-Bernalillo County, see 77 FR 71119 (November 29, 2012) for the final approval of the County's regional haze SIP, and see 82 FR 58347 (December 12, 2017) for the final approval of the County's five-year progress report. New Mexico and other states are in the process of developing SIPs for the second planning period, which are due to the EPA on July 31, 2021. *See* Final Rule, Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078 (January 10, 2017).

Comment: The commenter stated that the EPA should also issue a federal plan for the interstate transport elements, as these elements were due in October 2018, and it is now (at the time the comment was submitted) seven months late, and both the EPA and New Mexico have stated that the State does not have an interstate transport submission (section 110(a)(2)(D)(i)(I)) prepared by stating ''as a sufficient basis for a submittal addressing these requirements does not yet exist''. The commenter stated that since the EPA is formally recognizing in the proposed notice that the State has not made a submission for the interstate transport elements, this should be considered a finding of failure to submit, and finalization of this regulation should start a 24-month clock for the EPA to issue a federal implementation plan.

Response: In this action, the EPA is only evaluating whether the SIP submissions under review have met the statutory requirements they purport to address. Whether or not the State of New Mexico or Albuquerque-Bernalillo County have otherwise made a timely submission addressing the interstate transport elements (section 110(a)(2)(D)(i)(I)) for the 2015 O_3 NAAQS infrastructure requirements is outside the scope of this rulemaking because the EPA is not addressing these elements in this action. The EPA interprets its authority under CAA section 110(k) as affording the Agency the discretion to approve, disapprove, or conditionally approve, individual elements of the New Mexico infrastructure and transport SIP submissions for the 2015 O_3 NAAQS. The EPA views discrete infrastructure SIP requirements, such as the requirements of 110(a)(2)(D)(i)(I), as severable from other infrastructure SIP elements and interprets section 110(k) as allowing it to act on individual severable elements or requirements in a SIP submission. In short, the EPA has the discretion under CAA section 110(k) to act upon the various individual elements of a state's infrastructure SIP submission, separately or together, as appropriate. Here, the EPA has focused its evaluation on the individual infrastructure SIP elements addressed in the SIP submissions under review. The EPA will evaluate whether it is necessary to issue a separate notice to formally address the requirements of section 110(a)(2)(D)(i)(I) in the future.

Comment: We received one comment from the City of Albuquerque Environmental Health Department (EHD) stating that the EPA incorrectly made two statements which misstate New Mexico law in the April 18, 2019, proposal. The EHD provided proposed corrections to the two statements and clarified the EHD's authority under New Mexico law as well as the EHD's relation to the New Mexico Environmental Improvement Board (EIB) and the Albuquerque and Bernalillo County Joint Air Quality Control Board (Air Board).

The EHD stated that the first incorrect statement is: ''The AQCA [New Mexico Air Quality Control Act] and Ordinances [Albuquerque and Bernalillo County Joint Air Quality Control Board Ordinances] also state that the EHD is the administrative agency for the EIB and give the EHD authority to enforce air quality regulations.'' The EHD stated that the statement would be correct if changed to: ''The AQCA and Ordinances also state that the EHD is the administrative agency for the *Air Board* and give the EHD authority to enforce the *Air Board's* air quality regulations.''

The EHD stated that the second incorrect statement is: ''[T]he AQCA provides authority for the NMED and the EHD to enforce the requirements of the AQCA and any regulations of the EIB, permits, or final compliance orders.'' The EHD stated that the statement would be correct if changed to: ''[T]he AQCA provides authority for the NMED and the EHD to enforce the requirements of the AQCA and, *within their respective jurisdiction,* any *applicable* regulations, or permits, or final compliance orders *each agency (NMED and EHD) has issued.*''

Response: The EPA agrees with the EHD's corrected statements of its authority under New Mexico law.

III. Final Action

We are approving the November 1, 2018, and September 24, 2018, i-SIP submittals pertaining to the implementation, maintenance, and enforcement of the 2015 O_3 NAAQS, including two of the transport sub-elements (CAA section 110(a)(2)(D)(i)(II)), in the State of New Mexico and Albuquerque-Bernalillo County. Table 1 below outlines the final action EPA is taking on specific infrastructure elements.

TABLE 1—FINAL ACTION ON NEW MEXICO INFRASTRUCTURE SIP SUBMITTALS FOR THE 2015 O_3 NAAQS

Element	2015 O_3
(A): Emission limits and other control measures	A
(B): Ambient air quality monitoring and data systems	A
(C)(i): Enforcement of SIP measures	A
(C)(ii):PSD program for major sources and major modifications	A
(C)(iii): Permitting program for minor sources and minor modifications	A
(D)(i)(I): Prohibit emissions to other states which will (1) significantly contribute to nonattainment of the NAAQS, (2) interfere with maintenance of the NAAQS.	NA
(D)(i)(II): Prohibit emissions to other states which will (3) interfere with PSD requirements or (4) interfere with visibility protection	A
(D)(ii): Interstate and international pollution abatement	A
(E)(i): Adequate resources	A
(E)(ii): State boards	A
(E)(iii): Necessary assurances with respect to local agencies	A
(F): Stationary source monitoring system	A
(G): Emergency power	A
(H): Future SIP revisions	A

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TABLE 1—FINAL ACTION ON NEW MEXICO INFRASTRUCTURE SIP SUBMITTALS FOR THE 2015 O_3 NAAQS—Continued

Element	2015 O_3
(I): Nonattainment area plan or plan revisions under part D	+
(J)(i): Consultation with government officials	A
(J)(ii): Public notification	A
(J)(iii): PSD	A
(J)(iv): Visibility protection	+
(K): Air quality modeling and data	A
(L): Permitting fees	A
(M): Consultation and participation by affected local entities	A

Key to Table: A—Approved; +—Not germane to infrastructure SIPs; NA—No action.

We are also approving the November 16, 2018, submittal which consists of a revision to 20.2.3 NMAC (Ambient Air Quality Standards) . The approved SIP revision removes section 109 (Total Suspended Particulates) from 20.2.3 NMAC, as the EPA found that such a revision will not adversely affect the attainment of applicable CAA requirements.

IV. Incorporation by Reference

In this document, EPA is finalizing regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, EPA is finalizing the incorporation by reference of a revision to 20.2.3 NMAC. EPA has made, and will continue to make, these materials generally available through *www.regulations.gov* and at the EPA Region 6 Office (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information)''. Therefore, these materials have been approved by the EPA for inclusion in the SIP, have been incorporated by reference by the EPA into that plan, are fully federally enforceable under sections 110 and 113 of the CAA as of the effective date of the final rulemaking of the EPA's approval, and will be incorporated by reference in the next update to the SIP compilation.

V. Statutory and Executive Order Reviews

Under the Clean Air Act, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Is not an Executive Order 13771 (82 FR 9339, February 2, 2017) regulatory action because SIP approvals are exempted under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register.** This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 18, 2019. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Ozone, Particulate matter, Reporting and recordkeeping requirements.

Dated: August 28, 2019.

Kenley McQueen,

Regional Administrator, Region 6.

40 CFR part 52 is amended as follows:

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PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart GG—New Mexico

■ 2. Section 52.1620 is amended:

■ a. In paragraph (c), under the first table titled ''EPA Approved New Mexico Regulations,'' by revising the entry for Part 3;

■ b. In paragraph (e), under the second table titled ''EPA-Approved Nonregulatory Provisions and Quasi-Regulatory Measures in the New Mexico SIP,'' by adding an entry at the end for ''Infrastructure for the 2015 Ozone NAAQS''.

The revision and addition read as follows:

§ 52.1620 Identification of plan.

* * * * *

(c) * * *

EPA APPROVED NEW MEXICO REGULATIONS

State citation	Title/subject	State approval/ effective date	EPA approval date	Comments
New Mexico Administrative Code (NMAC) Title 20—Environment Protection Chapter 2—Air Quality				
* * *	*	*	*	*
Part 3	Ambient Air Quality Standards	11/16/2018	9/18/2019, [Insert **Federal Register** citation].	
* * *	*	*	*	*

* * * * *

(e) * * *

EPA-APPROVED NONREGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES IN THE NEW MEXICO SIP

Name of SIP provision	Applicable geographic or nonattainment area	State submittal/ effective date	EPA approval date	Explanation
* *	*	*	* *	* *
Infrastructure for the 2015 Ozone NAAQS.	Statewide	9/24/2018, 11/1/2018	9/18/2019, [Insert **Federal Register** citation].	SIPs adopted by NMED and City of Albuquerque. Does not address CAA section 110(a)(2)(D)(i)(I).

[FR Doc. 2019–19500 Filed 9–17–19; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2019–0036; FRL–9999–67–Region 3]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Infrastructure Requirements for the 2015 Ozone National Ambient Air Quality Standard

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving a state implementation plan (SIP) revision submitted by the State of Maryland for the 2015 ozone national ambient air quality standard (NAAQS or standard). Whenever EPA promulgates a new or revised NAAQS, states are required to make a SIP submission showing how the existing approved SIP has all the provisions necessary to meet certain SIP requirements for the new or revised NAAQS, or to add any needed provisions necessary to meet these requirements. The SIP revision is required to address basic program elements, including, but not limited to, regulatory structure, monitoring, modeling, legal authority, and adequate resources necessary to assure attainment and maintenance of the standards. These elements are referred to as infrastructure requirements. Maryland has made a submittal addressing the infrastructure requirements for the 2015 ozone NAAQS. EPA is approving Maryland's SIP revision addressing the infrastructure requirements for the 2015 ozone NAAQS in accordance with the requirements of section 110(a) of the Clean Air Act (CAA).

DATES: This final rule is effective on October 18, 2019.

ADDRESSES: EPA has established a docket for this action under Docket ID Number EPA–R03–OAR–2019–0036. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available through *https://www.regulations.gov,* or please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section for additional availability information.

FOR FURTHER INFORMATION CONTACT: Ellen Schmitt, Planning & Implementation Branch (3AD30), Air & Radiation Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103. The telephone number is (215)

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Part II

Environmental Protection Agency

40 CFR Parts 51, 52, 72 et al.
Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals; Final Rule

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 72, 78, and 97

[EPA–HQ–OAR–2009–0491; FRL–9436–8]

RIN 2060–AP50

Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, EPA is limiting the interstate transport of emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) that contribute to harmful levels of fine particle matter ($PM_{2.5}$) and ozone in downwind states. EPA is identifying emissions within 27 states in the eastern United States that significantly affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS. Also, EPA is limiting these emissions through Federal Implementation Plans (FIPs) that regulate electric generating units (EGUs) in the 27 states. This action will substantially reduce adverse air quality impacts in downwind states from emissions transported across state lines. In conjunction with other federal and state actions, it will help assure that all but a handful of areas in the eastern part of the country achieve compliance with the current ozone and $PM_{2.5}$ NAAQS by the deadlines established in the Clean Air Act (CAA or Act). The FIPs may not fully eliminate the prohibited emissions from certain states with respect to the 1997 ozone NAAQS for two remaining downwind areas and EPA is committed to identifying any additional required upwind emission reductions and taking any necessary action in a future rulemaking. In this action, EPA is also modifying its prior approvals of certain State Implementation Plan (SIP) submissions to rescind any statements that the submissions in question satisfy the interstate transport requirements of the CAA or that EPA's approval of the SIPs affects our authority to issue interstate transport FIPs with respect to the 1997 fine particulate and 1997 ozone standards for 22 states. EPA is also issuing a supplemental proposal to request comment on its conclusion that six additional states significantly affect downwind states' ability to attain and maintain compliance with the 1997 ozone NAAQS.

DATES: This final rule is effective on October 7, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2009–0491. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA Docket Center, EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For general questions concerning this action, please contact Ms. Meg Victor, Clean Air Markets Division, Office of Atmospheric Programs, Mail Code 6204J, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 343–9193; fax number: (202) 343–2359; e-mail address: *victor.meg@epa.gov.* For legal questions, please contact Ms. Sonja Rodman, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, telephone (202) 564–4079; e-mail address: *rodman.sonja@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

AQAT Air Quality Assessment Tool
ARP Acid Rain Program
BART Best Available Retrofit Technology
BACT Best Available Control Technology
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CAMx Comprehensive Air Quality Model with Extensions
CBI Confidential Business Information
CCR Coal Combustion Residuals
CEM Continuous Emissions Monitoring
CENRAP Central Regional Air Planning Association
CFR Code of Federal Regulations
DEQ Department of Environmental Quality
DSI Dry Sorbent Injection
EGU Electric Generating Unit
FERC Federal Energy Regulatory Commission
FGD Flue Gas Desulfurization
FIP Federal Implementation Plan
FR **Federal Register**
EPA U.S. Environmental Protection Agency
GHG Greenhouse Gas
GW Gigawatts
Hg Mercury
ICR Information Collection Request
IPM Integrated Planning Model
km Kilometers
lb/mmBtu Pounds Per Million British Thermal Unit
LNB Low-NO_X Burners
MACT Maximum Achievable Control Technology
MATS Modeled Attainment Test Software
$\mu g/m^3$ Micrograms Per Cubic Meter
MSAT Mobile Source Air Toxics
MOVES Motor Vehicle Emission Simulator
NAAQS National Ambient Air Quality Standards
NBP NO_X Budget Trading Program
NEI National Emission Inventory
NESHAP National Emissions Standards for Hazardous Air Pollutants
NO_X Nitrogen Oxides
NODA Notices of Data Availability
NSPS New Source Performance Standard
NSR New Source Review
OFA Overfire Air
OSAT Ozone Source Apportionment Technique
OTAG Ozone Transport Assessment Group
ppb Parts Per Billion
$PM_{2.5}$ Fine Particulate Matter, Less Than 2.5 Micrometers
PM_{10} Fine and Coarse Particulate Matter, Less Than 10 Micrometers
PM Particulate Matter
ppm Parts Per Million
PUC Public Utility Commission
RIA Regulatory Impact Analysis
SCR Selective Catalytic Reduction
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-catalytic Reduction
SO_2 Sulfur Dioxide
SO_X Sulfur Oxides, Including Sulfur Dioxide (SO_2) and Sulfur Trioxide (SO_3)
TAF Terminal Area Forecast
TCEQ Texas Commission on Environmental Quality
TIP Tribal Implementation Plan
TLN3 Tangential Low NO_X
TPY Tons Per Year
TSD Technical Support Document
WRAP Western Regional Air Partnership

II. General Information

A. Does this action apply to me?

This rule affects EGUs, and regulates the following groups:

Industry group	NAICS [a]
Utilities (electric, natural gas, other systems.) ...	2211, 2212, 2213

[a] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists

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the types of entities that EPA is aware of that could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your facility would be regulated by the proposed rule, you should carefully examine the applicability criteria in proposed §§ 97.404, 97.504, and 97,604.

B. How is the preamble organized?

III. Executive Summary

The CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS. In this final rule, EPA finds that emissions of SO_2 and NO_X in 27 eastern, midwestern, and southern states contribute significantly to nonattainment or interfere with maintenance in one or more downwind states with respect to one or more of three air quality standards—the annual $PM_{2.5}$ NAAQS promulgated in 1997, the 24-hour $PM_{2.5}$ NAAQS promulgated in 2006, and the ozone NAAQS promulgated in 1997 (EPA uses the term ''states'' to include the District of Columbia in this preamble).

These emissions are transported downwind either as SO_2 and NO_X or, after transformation in the atmosphere, as fine particles or ozone. This final rule identifies emission reduction responsibilities of upwind states, and also promulgates enforceable FIPs to achieve the required emission reductions in each state through cost-effective and flexible requirements for power plants. Each state has the option of replacing these federal rules with state rules to achieve the required amount of emission reductions from sources selected by the state.

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Section 110(a)(2)(D)(i)(I) of the CAA requires the elimination of upwind state emissions that significantly contribute to nonattainment or interfere with maintenance of a NAAQS in another state. Elimination of these upwind state emissions may not necessarily, in itself, fully resolve nonattainment or maintenance problems at downwind state receptors. Downwind states also have control responsibilities because, among other things, the Act requires each state to adopt enforceable plans to attain and maintain air quality standards. Indeed, states have put in place measures to reduce local emissions that contribute to nonattainment within their borders. Section 110(a)(2)(D)(i)(I) only requires the elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states; it does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS.

The reductions obtained through the Transport Rule will help all but a few downwind areas come into attainment with and maintain the 1997 annual $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the 1997 ozone NAAQS. With respect to the annual $PM_{2.5}$ NAAQS, this rule finds that 18 states have SO_2 and annual NO_X emission reduction responsibilities, and this rule quantifies each state's full emission reduction responsibility under section 110(a)(2)(D)(i)(I). *See* Table III–1 for the list of these states. With these reductions, EPA projects that no areas will have nonattainment or maintenance concerns with respect to the annual $PM_{2.5}$ NAAQS.

With respect to the 24-hour $PM_{2.5}$ NAAQS, this rule finds that 21 states have SO_2 and annual NO_X emission reduction responsibilities, and this rule quantifies each state's full emission reduction responsibility under 110(a)(2)(D)(i)(I). *See* Table III–1 for the list of these states. In all, this rule requires emission reductions related to interstate transport of fine particles in 23 states. With these reductions, as discussed in section VI.D of this preamble, only one area (Liberty-Clairton) is projected to remain in nonattainment, and three other areas (Chicago,[1] Detroit, and Lancaster) are projected to have remaining maintenance concerns for the 24-hour $PM_{2.5}$ NAAQS.

With respect to the 1997 ozone NAAQS, this rule finds that 20 states have ozone-season NO_X emission reduction responsibilities. For 10 of these states this rule quantifies the state's full emission reduction responsibility under section 110(a)(2)(D)(i)(I).[2] For 10 additional states, EPA quantifies in this rule the ozone-season NO_X emission reductions that are necessary but may not be sufficient to eliminate all significant contribution to nonattainment and interference with maintenance in other states.[3] *See* Table III–1 for the complete list of 20 states required to reduce ozone-season NO_X emissions in this rule. With the Transport Rule reductions, only one area (Houston) is projected to remain in nonattainment, and one area (Baton Rouge) to have a remaining maintenance concern with respect to the 1997 ozone NAAQS. The 10 states upwind of either of these two areas are the states for which additional reductions may be necessary to fully eliminate each state's significant contribution to nonattainment and interference with maintenance, as discussed in section VI of this preamble.[4]

As discussed further below, EPA's analysis also demonstrates that six additional states should be required to reduce ozone-season NO_X emissions. EPA is issuing a supplemental proposal to request comment on requiring ozone-season NO_X reductions in these six states. For five of these six states, EPA's analysis identifies the state's full emission reduction responsibility under section 110(a)(2)(D)(i)(I), and for the remaining one state EPA's analysis identifies reductions that are necessary but may not be sufficient to satisfy the requirements of 110(a)(2)(D)(i)(I).[5]

On January 19, 2010, EPA proposed revisions to the 8-hour ozone NAAQS that the Agency had issued March 12, 2008 (75 FR 2938); the Agency intends to finalize its reconsideration in the summer of 2011. EPA intends to propose a rule to address transport with respect to the reconsidered 2008 ozone NAAQS as expeditiously as possible after reconsideration is completed. EPA intends to include in that proposed rule requirements to address any remaining significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone NAAQS for the states identified in this final rule, or the associated supplemental notice of proposed rulemaking, for which EPA was unable to fully quantify the emissions that must be prohibited to satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS.

The Act requires EPA to conduct periodic reviews of each of the NAAQS. When NAAQS are set or revised, the CAA requires revision of SIPs to ensure the standards are met expeditiously and within relevant timetables in the Act. If more protective NAAQS are promulgated, in the case of pollutants for which interstate transport is important, additional emission reductions to address transported pollution may be required from the power sector, from other sectors, and from sources in additional states. EPA will act promptly to promulgate any future rules addressing transport with respect to revised NAAQS.

The Transport Rule requires substantial near-term emission reductions in every covered state to address each state's significant contribution to nonattainment and interference with maintenance downwind. This rule achieves these reductions through FIPs that regulate the power sector using air quality-assured trading programs whose assurance provisions ensure that necessary reductions will occur within every covered state. This remedy structure is substantially similar to the preferred trading remedy structure presented in the proposal. The Transport Rule's air quality-assured trading approach will assure

[1] This area is not currently designated as nonattainment for the 24-hour $PM_{2.5}$ standard. EPA is portraying the receptors and counties in this area as a single 24-hour maintenance area based on the annual $PM_{2.5}$ nonattainment designation of Chicago-Gary-Lake County, IL-IN.

[2] The 10 states for which this rule quantifies the state's full responsibility under section 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS are Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Virginia, and West Virginia.

[3] The 10 states for which this rule quantifies reductions that are necessary but may not be sufficient to satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS are Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Tennessee, and Texas.

[4] This preamble uses the term ''significant contribution'' only in the context of the CAA section 110(a)(2)(D)(i)(I) requirement that states prohibit emissions that ''contribute significantly to nonattainment'' in any other state with respect to any primary or secondary NAAQS. Thus, a significant contribution, as used in this preamble, is one that is significant for purposes of CAA section 110(a)(2)(D)(i)(I) as coming from a particular state.

[5] The five states addressed in the supplemental proposal for which EPA's analysis identifies the state's full reduction responsibility under section 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS are Iowa, Kansas, Michigan, Oklahoma, and Wisconsin. The one state addressed in the supplemental proposal for which EPA's analysis identifies reductions that are necessary but may not be sufficient to satisfy section 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS is Missouri.

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environmental results in each state while providing market-based flexibility to covered sources through interstate trading. The final rule includes four air quality-assured trading programs: An annual NO_X trading program, an ozone-season NO_X trading program, and two separate SO_2 trading programs (''SO_2 Group 1'' and ''SO_2 Group 2''), as discussed further in sections VI and VII, below.

The first phase of Transport Rule compliance commences January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone-season NO_X reductions. The second phase of Transport Rule reductions, which commences January 1, 2014, increases the stringency of SO_2 reductions in a number of states as discussed further below.

EPA projects that with the Transport Rule, covered EGU will substantially reduce SO_2, annual NO_X and ozone-season NO_X emissions, as shown in Tables III–2 and III–3, below. This rule generally covers electric generating units that are fossil fuel-fired boilers and turbines producing electricity for sale, as detailed in section VII.B.

EPA is promulgating the Transport Rule in response to the remand of the Clean Air Interstate Rule (CAIR) by the U.S. Court of Appeals for the District of Columbia Circuit (''Court'') in 2008. CAIR, promulgated May 12, 2005 (70 FR 25162), required 29 states to adopt and submit revisions to their State Implementation Plans (SIPs) to eliminate SO_2 and NO_X emissions that contribute significantly to downwind nonattainment of the $PM_{2.5}$ and ozone NAAQS promulgated in July 1997. CAIR covered a similar but not identical set of states as the Transport Rule. CAIR FIPs were promulgated April 26, 2006 (71 FR 25328) to regulate electric generating units in the covered states and achieve the emission reduction requirements established by CAIR until states could submit and obtain approval of SIPs to achieve the reductions.

In July 2008, the Court found CAIR and the CAIR FIPs unlawful. *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), modified on rehearing, *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008). The Court's original decision vacated CAIR. *North Carolina,* 531 F.3d at 929–30. However, the Court subsequently remanded CAIR to EPA without vacatur because it found that ''allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR.'' *North Carolina,* 550 F.3d at 1178. The CAIR requirements have remained in place while EPA has developed the Transport Rule to replace them.

EPA's approach in the Transport Rule to measure and address each state's significant contribution to downwind nonattainment and interference with maintenance is guided by and consistent with the Court's opinion in *North Carolina* and addresses the flaws in CAIR identified by the Court therein. This final rule also responds to extensive public comments and stakeholder input received during the public comment periods in response to the proposal and subsequent Notices of Data Availability (NODAs).

In this action, EPA both identifies and addresses emissions within states that significantly contribute to nonattainment or interfere with maintenance in other downwind states. In developing this rule, EPA used a state-specific methodology to identify emission reductions that must be made in covered states to address the CAA section 110(a)(2)(D)(i)(I) prohibition on emissions that significantly contribute to nonattainment or interfere with maintenance in a downwind state. EPA believes this methodology addresses the Court's concern that the approach used in CAIR was insufficiently state-specific. EPA used detailed air quality analysis to determine whether a state's contribution to downwind air quality problems is at or above specific thresholds. A state is covered by the Transport Rule if its contribution meets or exceeds one of those air quality thresholds and the Agency identifies, using a multi-factor analysis that takes into account both air quality and cost considerations, emissions within the state that constitute the state's significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone or the 1997 annual or 2006 24-hour $PM_{2.5}$ NAAQS. Section 110(a)(2)(D)(i)(I) requires states to eliminate the emissions that constitute this ''significant contribution'' and ''interference with maintenance.'' [6]

In this final rule, EPA determined the emission reductions required from all upwind states to eliminate significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone, 1997 annual $PM_{2.5}$, and 2006 24-hour $PM_{2.5}$ NAAQS, using, in part, an assessment of modeled air quality in 2012 and 2014. EPA first identified the following two sets of downwind receptors: (1) Receptors that EPA projects will have nonattainment problems; and, (2) receptors that EPA projects may have difficulty maintaining the NAAQS based on historic variation in air quality. To identify areas that may have problems attaining or maintaining these air quality standards, EPA projected a suite of future air quality design values, based on measured data during the period 2003 through 2007. EPA used the average of these future design values to assess whether an area will be in nonattainment. EPA used the maximum projected future design value to assess whether an area may have difficulty maintaining the relevant NAAQS (*i.e.,* whether an area has a reasonable possibility of being in nonattainment under adverse emission and weather conditions). Section V.C of this preamble details the Transport Rule's approach to identify downwind nonattainment and maintenance areas.

After identifying downwind nonattainment and/or maintenance areas, EPA next used air quality modeling to determine which upwind states are projected to contribute at or above threshold levels to the air quality problems in those areas. Section V.D details the choice of air quality thresholds and the approach to determine how much each upwind state contributes. States whose contributions meet or exceed the threshold levels were analyzed further, as detailed in section VI, to determine whether they significantly contribute to nonattainment or interfere with maintenance of a relevant NAAQS, and if so, the quantity of emissions that constitute their significant contribution and interference with maintenance.

When EPA proposed this air-quality and cost-based multi-factor approach to identify emissions that constitute significant contribution to nonattainment and interference with maintenance from upwind states with respect to the 1997 ozone, annual $PM_{2.5}$, and 2006 24-hour $PM_{2.5}$ NAAQS, the Agency indicated that the approach was designed to be applicable to both current and potential future ozone and $PM_{2.5}$ NAAQS (75 FR 45214). EPA believes that the Transport Rule's approach of using air-quality thresholds to determine upwind-to-downwind-state linkages and using the air-quality and cost-based multi-factor approach to determine the quantity of emissions that each upwind state must eliminate, *i.e.,* the state's significant contribution to nonattainment and interference with maintenance, could serve as a precedent for quantifying upwind state emission reduction responsibilities with respect

[6] In this preamble, EPA uses the terms ''significant contribution'' and ''interference with maintenance'' to refer to the emissions that must be prohibited pursuant to section 110(a)(2)(D)(i)(I) because they significantly contribute to nonattainment or interfere with maintenance of the NAAQS in another state.

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to potential future NAAQS, as discussed further in section VI.A of this preamble. The Agency further believes that the final Transport Rule demonstrates the strong value of this approach for addressing the role of interstate transport of air pollution in communities' ability to comply with current and future NAAQS.

EPA thus identified specific emission reduction responsibilities for each upwind state found to significantly contribute to nonattainment or interfere with maintenance in other states. Using that information, EPA developed individual state budgets for emissions from covered units under the Transport Rule. The Transport Rule emission budgets are based on EPA's state-by-state analysis of each upwind state's significant contribution to nonattainment and interference with maintenance. Because each state's budget is directly linked to this state-specific analysis of the state's obligations pursuant to section 110(a)(2)(D)(i)(I), this approach addresses the Court's concerns about the development of CAIR budgets.

In this rule, EPA is finalizing SO_2 and annual NO_X budgets for each state covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS and an ozone-season NO_X budget for each state covered for the ozone NAAQS. A state's emission budget is the quantity of emissions that will remain from covered units under the Transport Rule after elimination of significant contribution to nonattainment and interference with maintenance in an average year (*i.e.,* before accounting for the inherent variability in power system operations).[7]

Baseline power sector emissions from a state can be affected by changing weather patterns, demand growth, or disruptions in electricity supply from other units or from the transmission grid. As a consequence, emissions could vary from year to year even in a state where covered sources have installed all controls and taken all measures necessary to eliminate the state's significant contribution to nonattainment and interference with maintenance. As described in detail in sections VI and VII of this preamble, the Transport Rule accounts for the inherent variability in power system operations through ''assurance provisions'' based on state-specific variability limits which extend above the state budgets to form each state's ''assurance level.'' The state assurance levels take into account the inherent variability in baseline emissions from year to year. The final Transport Rule FIPs will implement assurance provisions starting in 2012 as discussed in section VII, below.

The emission reduction requirements (*i.e.,* the ''remedy'') EPA is promulgating in this rule respond to the Court's concerns that in CAIR, EPA had not shown that the emission reduction requirements would get all necessary reductions within the state as required by section 110(a)(2)(D)(i)(I). The Transport Rule FIPs include assurance provisions specifically designed to ensure that no state's emissions are allowed to exceed that specific state's budget plus the variability limit (*i.e.,* the state's assurance level).

Each state's Transport Rule SO_2, annual NO_X, or ozone-season NO_X emission budget is composed of a number of emission allowances (''allowances'') equivalent to the tonnage of that specific state budget. Under the Transport Rule FIPs, EPA is distributing (''allocating'') allowances under each state's budget to covered units in that state. In this rule, EPA analyzed each individual state's significant contribution to nonattainment and interference with maintenance and calculated budgets that represent each state's emissions after the elimination of those prohibited emissions in an average year. The methodology used to allocate allowances to individual units in a particular state has no impact on that state's budget or on the requirement that the state's emissions not exceed that budget plus the variability limit; the allocation methodology therefore has no impact on the rule's ability to satisfy the statutory mandate of CAA section 110(a)(2)(D)(i)(I).

The Transport Rule's approach to allocate emission allowances to existing units is based on historic heat-input data, as detailed in section VII.D of this preamble. The Transport Rule SO_2, annual NO_X, and ozone-season NO_X emission allowances each authorize the emission of one ton of SO_2, annual NO_X, or ozone-season NO_X emissions, respectively, during a Transport Rule control period, and are the currency in the Transport Rule's air quality-assured trading programs. As discussed in section IX.A.2 below, EPA is creating these Transport Rule allowances as distinct compliance instruments with no relation to allowances from the CAIR trading programs. EPA agrees with the general principle that it is desirable, where possible, to provide continuity under successive regulatory trading programs, for example through the carryover of allowances from one program into a subsequent one. However, EPA is promulgating the Transport Rule as a court-ordered replacement for (not a successor to) CAIR's trading programs. In light of the specific circumstances of this case, including legal and technical issues discussed in Section IX.A.2 below, the final rule will not allow any carryover of banked SO_2 or NO_X allowances from the Title IV or CAIR trading programs. EPA will strongly consider administrative continuity of this rule's trading programs under any future actions designed to address related problems of interstate transport of air pollution. A state may submit a SIP revision under which the state (rather than EPA) would determine allocations for one or more of the Transport Rule trading programs beginning with vintage year 2013 or later allowances.[8] Section X of this preamble discusses the final rule's provisions for SIP submissions in detail.

Table III–1 lists states covered by the Transport Rule for $PM_{2.5}$ and ozone. It also, with respect to $PM_{2.5}$, identifies whether EPA determined the state was significantly contributing to nonattainment or interfering with maintenance of the 1997 annual $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, or both. As discussed below, the Transport Rule sorts the states required to reduce SO_2 emissions due to their contribution to $PM_{2.5}$ downwind into two groups of varying reduction stringency, with ''Group 1'' states subject to greater SO_2 reduction stringency than ''Group 2'' states starting in 2014. Table III–1 also lists which SO_2 Group each of the states is in.

[7] For the states discussed above for which EPA has quantified the minimum amount of emission reductions needed to make measurable progress toward satisfying the state's section 110(a)(2)(D)(i)(I) responsibility, the emission budget is the quantity of emissions that will remain from covered units after removal of those emissions.

[8] This final rule allows states to make 2013 allowance allocations through the use of a SIP revision that is narrower in scope than the other SIP revisions states can use to replace the FIPs and/or to make allocation decisions for 2014 and beyond, as discussed in section X.

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TABLE III–1—STATES THAT SIGNIFICANTLY CONTRIBUTE TO NONATTAINMENT OR INTERFERE WITH MAINTENANCE OF A NAAQS DOWNWIND IN THE FINAL TRANSPORT RULE

State	1997 Ozone NAAQS	1997 Annual $PM_{2.5}$ NAAQS	2006 24-Hour $PM_{2.5}$ NAAQS	SO_2 group
Alabama	X	X	X	2
Arkansas	X			
Florida	X			
Georgia	X	X	X	2
Illinois	X	X	X	1
Indiana	X	X	X	1
Iowa		X	X	1
Kansas			X	2
Kentucky	X	X	X	1
Louisiana	X			
Maryland	X	X	X	1
Michigan		X	X	1
Minnesota			X	2
Mississippi	X			
Missouri		X	X	1
Nebraska			X	2
New Jersey	X		X	1
New York	X	X	X	1
North Carolina	X	X	X	1
Ohio	X	X	X	1
Pennsylvania	X	X	X	1
South Carolina	X	X		2
Tennessee	X	X	X	1
Texas	X	X		2
Virginia	X		X	1
West Virginia	X	X	X	1
Wisconsin		X	X	1
Number of States	20	18	21	

As explained in this preamble, EPA has improved and updated both steps of its significant contribution analysis. It updated and improved the modeling platforms and modeling inputs used to identify states with contributions to certain downwind receptors that meet or exceed specified thresholds. It also updated and improved its analysis for identifying any emissions within such states that constitute the state's significant contribution to nonattainment or interference with maintenance. Therefore, the results of the analysis conducted for the final rule differ somewhat from the results of the analysis conducted for the proposal.[9]

With respect to the 1997 ozone NAAQS, the analysis EPA conducted for the proposal did not identify Wisconsin, Iowa and Missouri as states that significantly contribute to nonattainment or interfere with maintenance of the ozone NAAQS in another state. However, the analysis conducted for the final rule shows that emissions from these states do significantly contribute to nonattainment or interfere with maintenance of the ozone NAAQS in another state. EPA is not issuing FIPs with respect to the 1997 ozone NAAQS or finalizing ozone season NO_X budgets for these states in this rule. EPA is publishing a supplemental notice of proposed rulemaking that will provide an opportunity for public comment on our conclusion that these states significantly contribute to nonattainment or interfere with maintenance of the 1997 ozone NAAQS.

In the other direction, the analysis conducted for the proposal supported EPA's conclusion at the time that Connecticut, Delaware, and the District of Columbia significantly contributed to nonattainment or interfered with maintenance with respect to the 1997 ozone NAAQS, whereas the modeling for the final rule no longer supports that conclusion for those states.

Additionally, the modeling conducted for the final rule identified two ozone maintenance receptors that were not identified in the modeling conducted for the proposal—Allegan County (MI) and Harford County (MD). Five states that EPA identified as significantly contributing to maintenance problems at the Allegan and/or Harford County receptors in the modeling for the final rule uniquely contribute to these receptors, *i.e.,* absent these receptors the states would not be covered by the Transport Rule ozone-season program. The five states that uniquely contribute to these receptors are Iowa, Kansas, Michigan, Oklahoma, and Wisconsin. EPA is not issuing FIPs with respect to the 1997 ozone NAAQS or finalizing ozone-season NO_X budgets for these states in this rule. EPA is publishing a supplemental notice of proposed rulemaking that will provide an opportunity for public comment on our conclusion that these states significantly contribute to nonattainment or interfere with maintenance of the 1997 ozone NAAQS.

EPA did not change its methodology between the proposed Transport Rule and the final Transport Rule for identifying upwind states that significantly contribute to nonattainment or interfere with maintenance in other states; nor did EPA change its methodology for identifying receptors of concern with respect to maintenance of the 1997 ozone NAAQS. The final rule's air quality modeling identifies the new states and new receptors described above based on updated input information (including emission inventories), much of which was provided to EPA through public comment on the proposal and subsequent NODAs. Section V of this preamble details the approach EPA used

[9] EPA updated its modeling platforms and modeling inputs in response to public comments received on the proposed Transport Rule and subsequent NODAs and performed other standard updates.

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to identify contributing states and receptors of concern.

With respect to the annual $PM_{2.5}$ NAAQS, the analysis EPA conducted for the proposal supported EPA's conclusion that the states of Delaware, the District of Columbia, Florida, Louisiana, Minnesota, New Jersey, and Virginia were significantly contributing to nonattainment and interfering with maintenance of the annual $PM_{2.5}$ NAAQS while the final rule's analysis does not. Also, with respect to the 24-hour $PM_{2.5}$ NAAQS, the analysis conducted for the proposal supported EPA's conclusion that the states of Connecticut, Delaware, the District of Columbia, and Massachusetts were significantly contributing to nonattainment or interfering with maintenance in other states while the analysis conducted for the final rule did not.

In the proposal EPA also requested comment on whether Texas should be included in the Transport Rule for annual $PM_{2.5}$. EPA's analysis for the proposal showed that emissions in Texas would significantly contribute to nonattainment or interfere with maintenance of the annual $PM_{2.5}$ NAAQS if Texas were not included in the rule for $PM_{2.5}$. The proposal did not include an illustrative budget for Texas or illustrative allowance allocations. However, the budgets and allowance allocations provided for other states in the proposal were included solely to illustrate the result of applying EPA's proposed methodology for quantifying significant contribution to the data EPA proposed to use. EPA provided an ample opportunity for comment on this methodology and on the data, including data regarding emissions from Texas sources, used in the significant contribution analysis. EPA received numerous comments on and corrections to Texas-specific data. The modeling conducted for the final rule demonstrates that Texas significantly contributes to nonattainment or interferes with maintenance of the annual $PM_{2.5}$ NAAQS in another state. EPA provided a full opportunity for comment on whether Texas should be included in the rule for annual $PM_{2.5}$, as well as on the methodology and data used for the significant contribution analysis for the final rule. EPA therefore believes its determination that Texas must be included in the rule for annual $PM_{2.5}$ is a logical outgrowth of its proposal.

With respect to the 24-hour $PM_{2.5}$ NAAQS, the analysis EPA conducted for the proposal did not identify Texas as a state that significantly contributes to nonattainment or interferes with maintenance of 24-hour $PM_{2.5}$ in another state. However, the analysis conducted for the final rule shows that emissions from Texas do significantly contribute to nonattainment of the 24-hour $PM_{2.5}$ NAAQS in another state. EPA is not issuing a FIP for Texas with respect to the 24-hour $PM_{2.5}$ NAAQS in this rule. However, EPA believes that the FIP for Texas with respect to the 1997 annual $PM_{2.5}$ NAAQS also addresses the emissions in Texas that significantly contribute to nonattainment and interference with maintenance of the 2006 24-hour $PM_{2.5}$ NAAQS in another state.

The final rule, however, does not cover the states of Connecticut, Delaware, the District of Columbia, Florida, Louisiana, or Massachusetts for annual or 24-hour $PM_{2.5}$ as the analysis for the final rule does not support their inclusion.

The Transport Rule FIPs require the 23 states covered for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS to reduce SO_2 and annual NO_X emissions by specified amounts. The FIPs require the 20 states covered for purposes of the ozone NAAQS to reduce ozone-season NO_X emissions by specified amounts. As discussed in detail in section VI, below, the 23 states covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS are grouped in two tiers reflecting the stringency of SO_2 reductions required to eliminate that state's significant contribution to nonattainment and interference with maintenance downwind. The more-stringent SO_2 tier (''Group 1'') is comprised of the 16 states indicated in Table III–1, above, and the less-stringent SO_2 tier (''Group 2'') is comprised of the 7 states identified in the table. The two SO_2 trading programs are exclusive, *i.e.,* a covered source in a Group 1 state may use only a Group 1 allowance for compliance, and likewise a source in a Group 2 state may use only a Group 2 allowance for compliance. In Group 1 states, the SO_2 reduction requirements become more stringent in the second phase, which starts in 2014.

In response to the Court's opinion in *North Carolina,* EPA has coordinated the Transport Rule's compliance deadlines with the NAAQS attainment deadlines that apply to the downwind nonattainment and maintenance areas. The Transport Rule requires that all significant contribution to nonattainment and interference with maintenance identified in this action with respect to the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS be eliminated by no later than 2014, with an initial phase of reductions starting in 2012 to ensure that reductions are made as expeditiously as practicable and, consistent with the Court's remand, to ''preserve the environmental values covered by CAIR.'' Sources must comply by January 1, 2012 and January 1, 2014 for the first and second phases, respectively.

With respect to the 1997 ozone NAAQS, the Transport Rule requires NO_X reductions starting in 2012 to ensure that reductions are made as expeditiously as practicable to assist downwind state attainment and maintenance of the standard. Sources must comply by May 1, 2012. The Transport Rule's compliance schedule and alignment with downwind NAAQS attainment deadlines are discussed in detail in section VII below.

Table III–2 shows projected Transport Rule emissions compared to projected base case emissions, and Table III–3 shows projected Transport Rule emissions compared to historical emissions (*i.e.,* 2005 emissions), for the power sector in all Transport Rule states. The ozone-season NO_X results shown in Tables III–2 and III–3 are based on analysis of the group of 26 states that would be covered for the ozone-season program if EPA finalizes the supplemental proposal regarding ozone-season requirements for Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin.

TABLE III–2—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSION REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASE CASE WITHOUT TRANSPORT RULE OR CAIR **

[Million tons]

	2012 Base case emissions	2012 Transport rule emissions	2012 Emission reductions	2014 Base case emissions	2014 Transport rule emissions	2014 Emission reductions
SO_2	7.0	3.0	4.0	6.2	2.4	3.9
Annual NO_X	1.4	1.3	0.1	1.4	1.2	0.2

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TABLE III–2—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSION REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASE CASE WITHOUT TRANSPORT RULE OR CAIR **—Continued

[Million tons]

	2012 Base case emissions	2012 Transport rule emissions	2012 Emission reductions	2014 Base case emissions	2014 Transport rule emissions	2014 Emission reductions
Ozone-Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

* Note that numbers may not sum exactly due to rounding.
** As explained in section V.B, EPA's base case projections for the Transport Rule assume that CAIR is not in place.

Notes: The SO_2 and annual NO_X emissions in this table reflect EGUs in the 23 states covered by this rule for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS (Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin). The ozone-season NO_X emissions reflect EGUs in the 20 states covered by this rule for purposes of the ozone NAAQS (Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia) and the six states that would be covered for the ozone NAAQS if EPA finalizes its supplemental proposal (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin).

TABLE III–3—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSION REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 Actual emissions	2012 Transport rule emissions	2012 Emission reductions from 2005	2014 Transport rule emissions	2014 Emission reductions from 2005
SO_2	8.8	3.0	5.8	2.4	6.4
Annual NO_X	2.6	1.3	1.3	1.2	1.4
Ozone-Season NO_X	0.9	0.6	0.3	0.6	0.3

Notes: The SO_2 and annual NO_X emissions in this table reflect EGUs in the 23 states covered by this rule for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS (Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin). The ozone-season NO_X emissions reflect EGUs in the 20 states covered by this rule for purposes of the ozone NAAQS (Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia) and the six states that would be covered for the ozone NAAQS if EPA finalizes its supplemental proposal (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin).

In addition to the emission reductions shown above, EPA projects other substantial benefits of the Transport Rule, as described in section VIII in this preamble. EPA used air quality modeling to quantify the improvements in $PM_{2.5}$ and ozone concentrations that are expected to result from the Transport Rule emission reductions in 2014. The Agency used the results of this modeling to calculate the average and peak reduction in annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone concentrations for monitoring sites in the Transport Rule covered states (including the six states for which EPA issued a supplemental proposal for ozone-season NO_X requirements) in 2014.

For annual $PM_{2.5}$, the average reduction across all monitoring sites in covered states in 2014 is 1.41 microgram per meter cubed ($\mu g/m^3$) and the greatest reduction at a single site is 3.60 $\mu g/m^3$. For 24-hour $PM_{2.5}$, the average reduction across all monitoring sites in covered states in 2014 is 4.3 $\mu g/m^3$ and the greatest reduction at a single site is 11.6 $\mu g/m^3$. And finally, for 8-hour ozone, the average reduction across all monitoring sites in covered states in 2014 is 0.3 parts per billion (ppb) and the greatest is 3.9 ppb. *See* section VIII for further information on air quality improvements.

EPA estimated the Transport Rule's costs and benefits, including effects on sensitive and vulnerable and environmental justice communities. Table III–4, below, summarizes some of these results. Further discussion of the results is provided in preamble section VIII, below, and in the Regulatory Impact Analysis (RIA). Estimates here are subject to uncertainties discussed further in the RIA.

TABLE III–4.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL TRANSPORT RULE IN 2014

[Billions of 2007$] [a]

Description	Transport rule remedy (billions of 2007 $)	
	3% discount rate	7% discount rate
Social costs	$0.81	$0.81.
Total monetized benefits [b]	$120 to $280	$110 to $250.
Net benefits (benefits-costs)	$120 to $280	$110 to $250.

[a] All estimates are for 2014, and are rounded to two significant figures.

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[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ and ozone and the welfare benefits associated with improved visibility in Class I areas. The reduction in premature mortalities account for over 90 percent of total monetized $PM_{2.5}$ and ozone benefits.

As a result of updated analyses and in response to public comments, the final Transport Rule differs from the proposal in a number of ways. The differences between proposal and final rule are discussed throughout this preamble. Some key changes between proposal and final rule are that EPA:

- Updated emission inventories (resulting in generally lower base case emissions). *See* section V.C.
- Updated modeling and analysis tools (including improved alignment between air quality estimates and air quality modeling results). *See* sections V and VI.
- Updated conclusions regarding which states significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states. *See* Table III–1 and sections V.D and VI.
- Recalculated state budgets and variability limits, *i.e.,* state assurance levels, based on updated modeling. *See* section VI.
- Simplified variability limits for one-year application only. *See* section VI.E.
- Revised allocation methodology for existing and new units and revised new unit set-asides for new units in Transport Rule states and new units potentially locating in Indian country. *See* section VII.D.
- Changed start of assurance provisions to 2012 and increased assurance provision penalties. *See* section VII.E.
- Removed opt-in provisions. *See* section VII.B
- Added provisions for full and abbreviated Transport Rule SIP revisions. *See* section X.

EPA conducted substantial stakeholder outreach in developing the Transport Rule, starting with a series of ''listening sessions'' in the spring of 2009 with states, nongovernmental organizations, and industry. EPA docketed stakeholder-related materials in the Transport Rule docket (Docket ID No. EPA–HQ–OAR–2009–0491). The Agency conducted general teleconferences on the rule with tribal environmental professionals, conducted consultation with tribal governments, and hosted a webinar for communities and tribal governments. EPA continued to provide updates to regulatory partners and stakeholders through several conference calls with states as well as at conferences where EPA officials often made presentations. The Agency conducted additional stakeholder outreach during the public comment period. EPA responded to extensive public comments received during the public comment periods on the proposed rule and associated NODAs.

This Transport Rule is one of a series of regulatory actions to reduce the adverse health and environmental impacts of the power sector. EPA is developing these rules to address judicial review of previous rulemakings and to issue rules required by environmental laws. Finalizing these rules will effectuate health and environmental protection mandated by Congress while substantially reducing uncertainty over the future regulatory obligations of power plants, which will assist the power sector in planning for compliance more cost effectively. The Agency is providing full opportunity for notice and comment for each rule.

As discussed above, rules to address transport under revised NAAQS, including the reconsidered 2008 ozone NAAQS, may result in additional emission reduction requirements for the power sector. In addition, existing Clean Air Act rules establishing best available retrofit technology (BART) requirements and other requirements for addressing visibility and regional haze may also result in future state requirements for certain power plant emission reductions where needed.

On May 3, 2011 (76 FR 24976), EPA proposed national emission standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units under CAA section 112(d), also called Mercury and Air Toxics Standards (MATS), and proposed revised new source performance standards for fossil fuel-fired EGUs under section 111(b). As discussed in the EPA-led public listening sessions during February and March 2011, EPA is preparing to propose innovative, cost-effective and flexible greenhouse gas (GHG) emissions performance standards under section 111 for steam electric generating units, the largest U.S. source of greenhouse gas emissions. On April 20, 2011 (76 FR 22174), EPA proposed requirements under section 316(b) of the Clean Water Act for existing power generating facilities, manufacturing and industrial facilities that withdraw more than two million gallons per day of water from waters of the U.S. and use at least twenty-five percent of that water exclusively for cooling purposes. On June 21, 2010 (75 FR 35128), the Agency proposed to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act to address the risks from the disposal of CCRs generated from the combustion of coal at electric utilities and independent power producers.

EPA will coordinate utility-related air pollution rules with each other and with other actions affecting the power sector including these rules from EPA's Office of Water and its Office of Resource Conservation and Recovery to the extent consistent with legal authority in order to provide timely information needed to support regulated sources in making informed decisions. Use of a small number of air pollution control technologies, widely deployed, can assist with compliance for multiple rules. EPA also notes that the flexibility inherent in the allowance-trading mechanism included in the Transport Rule affords utilities themselves a degree of latitude to determine how best to integrate compliance with the emission reduction requirements of this rule and those of the other rules. EPA will pursue energy efficiency improvements in the use of electricity throughout the economy, along with other federal agencies, states and other groups, which will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

IV. Legal Authority, Environmental Basis, and Correction of CAIR SIP Approvals

A. EPA's Authority for Transport Rule

The statutory authority for this action is provided by the CAA, as amended, 42 U.S.C. 7401 *et seq.* Section 110(a)(2)(D) of the CAA, often referred to as the ''good neighbor'' provision of the Act, and requires states to prohibit certain emissions because of their impact on air quality in downwind states. Specifically, it requires all states, within 3 years of promulgation of a new or revised NAAQS, to submit SIPs that prohibit certain emissions of air pollutants because of the impact they would have on air quality in other states. 42 U.S.C. 7410(a)(2)(D). This action addresses the requirement in section 110(a)(2)(D)(i)(I) regarding the prohibition of emissions within a state that will significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other

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state. EPA has previously issued two rules interpreting and clarifying the requirements of section 110(a)(2)(D)(i)(I). The NO_X SIP Call, promulgated in 1998, was largely upheld by the U.S. Court of Appeals for the DC Circuit in *Michigan,* 213 F.3d 663. CAIR, promulgated in 2005, was remanded by the DC Circuit in *North Carolina,* 531 F.3d 896, *modified on reh'g,* 550 F.3d. 1176. These decisions provide additional guidance regarding the requirements of section 110(a)(2)(D)(i)(I) and are discussed later in this notice.

Section 301(a)(1) of the CAA also gives the Administrator of EPA general authority to prescribe such regulations as are necessary to carry out her functions under the Act. 42 U.S.C. 7601(a)(1). Pursuant to this section, EPA has authority to clarify the applicability of CAA requirements. In this action, among other things, EPA is clarifying the applicability of section 110(a)(2)(D)(i)(I) by identifying SO_2 and NO_X emissions that must be prohibited pursuant to this section with respect to the $PM_{2.5}$ NAAQS promulgated in 1997 and 2006 and the 8-hour ozone NAAQS promulgated in 1997.

Section 110(c)(1) requires the Administrator to promulgate a FIP at any time within 2 years after the Administrator finds that a state has failed to make a required SIP submission, finds a SIP submission to be incomplete or disapproves a SIP submission unless the state corrects the deficiency, and the Administrator approves the SIP revision, before the Administrator promulgates a FIP. 42 U.S.C. 7410(c)(1).

Tribes are not required to submit state implementation plans. However, as explained in EPA's regulations outlining Tribal Clean Air Act authority, EPA is authorized to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit and get EPA approval of an implementation plan. *See* 40 CFR 49.11(a); see also 42 U.S.C. section 7601(d)(4).

Section 110(k)(6) of the CAA gives the Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error.

B. Rulemaking History

The Transport Rule FIPs will limit the interstate transport of emissions of NO_X and SO_2 within 27 states in the eastern, midwestern, and southern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS.[10] Prior to this Transport Rule, CAIR was EPA's most recent regulatory action in a longstanding series of regulatory initiatives to address interstate transport of air pollution. The proposed Transport Rule preamble provides more information on EPA actions prior to CAIR (75 FR 45221–45225).

CAIR, promulgated May 12, 2005 (70 FR 25162), required 29 states to adopt and submit revisions to their SIPs to eliminate SO_2 and NO_X emissions that contribute significantly to downwind nonattainment of the $PM_{2.5}$ and ozone NAAQS promulgated in 1997. The states covered by CAIR were similar but not identical to the states covered by the Transport Rule. The CAIR FIPs, promulgated April 26, 2006 (71 FR 25328), regulated electric generating units in the covered states and achieved CAIR's emission reduction requirements unless or until states had approved SIPs to achieve the required reductions.

In July 2008, the DC Circuit Court found CAIR and the CAIR FIPs unlawful and vacated CAIR. *North Carolina,* 531 F.3d at 929–30. However, the Court subsequently remanded CAIR to EPA without vacatur in order to ''at least temporarily preserve the environmental values covered by CAIR.'' *North Carolina,* 550 F.3d at 1178. CAIR requirements have remained in place and CAIR's emission trading programs have operated while EPA developed replacement rules in response to the remand.

By promulgating the Transport Rule FIPs, EPA is responding to the Court's remand of CAIR and the CAIR FIPs and replacing those rules. The approaches EPA used in the Transport Rule to measure and address each state's significant contribution to downwind nonattainment and interference with maintenance are guided by and consistent with the Court's opinion in *North Carolina* and address the flaws in CAIR identified by the Court therein.

By notice of proposed rulemaking (Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 FR 45210; August 2, 2010), EPA proposed the Transport Rule to identify and limit NO_X and SO_2 emissions within 32 states in the eastern, midwestern, and southern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. EPA proposed to achieve the emission reductions under FIPs, which states may choose to replace by submitting SIPs for EPA approval. EPA proposed to limit emissions by regulating electric generating units in the 32 states with interstate emission trading programs and assurance provisions to ensure the required reductions occur in each covered state. EPA also requested comment on two alternative FIP remedies.

EPA supplemented the Transport Rule record with additional information relevant to the rulemaking in three NODAs for which EPA requested comments:

- Notice of Data Availability Supporting Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (75 FR 53613; September 1, 2010). This NODA provided an updated database of unit-level characteristics of EGUs included in EPA modeling, an updated version of the power sector modeling platform EPA used to support the final rule, and other input assumptions and data EPA provided for public review and comment.
- Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Revisions to Emission Inventories (75 FR 66055; October 27, 2010). This NODA provided additional information relevant to the rulemaking, including updated emission inventory data for 2005, 2012 and 2014 for several stationary and mobile source inventory components.
- Notice of Data Availability for Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New-Unit Allocations in Indian Country, and Allocations by States (76 FR 1109; January 7, 2011). This NODA provided additional information relevant to the rulemaking, including emissions allowance allocations for existing units calculated using two alternative methodologies, data supporting those calculations, information about an alternative approach to calculation of assurance provision allowance surrender requirements, allocations for new units locating in Indian country in Transport Rule states in the future, and provisions for states to submit SIPs providing for state allocation of allowances in the Transport Rule trading programs.

[10] As discussed in section III of this preamble, EPA is proposing to apply ozone-season NO_X requirements to additional states. If EPA finalizes that action as proposed, the total number of states covered by the Transport Rule FIPs would be 28.

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C. Air Quality Problems and NAAQS Addressed

1. Air Quality Problems and NAAQS Addressed

a. Fine Particles

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, health-related absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems. In addition to effects on public health, fine particles are linked to a number of public welfare effects, including (1) Reduced visibility (haze) in scenic areas, (2) effects caused by particles settling on ground or water, such as: making lakes and streams acidic, changing the nutrient balance in coastal waters and large river basins, depleting the nutrients in soil, damaging sensitive forests and farm crops, and affecting the diversity of ecosystems, and (3) staining and damaging of stone and other materials, including culturally important objects such as statues and monuments.

In 1997, EPA revised the NAAQS for PM to add new annual and 24-hour standards for fine particles, using $PM_{2.5}$ as the indicator (62 FR 38652). These revisions established an annual standard of 15 $\mu g/m^3$ and a 24-hour standard of 65 $\mu g/m^3$. During 2006, EPA revised the air quality standards for $PM_{2.5}$. The 2006 standards decreased the level of the 24-hour fine particle standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$, and retained the annual fine particle standard at 15 $\mu g/m^3$.

b. Ozone

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. At sufficient concentrations, short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that may require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, or a lifetime). There is also epidemiological evidence indicating a correlation between short-term ozone exposure and premature mortality.

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.,* harsh weather). In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems. Ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. In 1997, at the same time we revised the $PM_{2.5}$ standards, EPA issued its final action to revise the NAAQS for ozone (62 FR 38856) to establish new 8-hour standards. In this action published on July 18, 1997, we promulgated identical revised primary and secondary ozone standards that specified an 8-hour ozone standard of 0.08 parts per million (ppm). Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 0.08 ppm. In general, the 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards.

On March 12, 2008, EPA published a revision to the 8-hour ozone standard, lowering the level from 0.08 ppm to 0.075 ppm. On September 16, 2009, EPA announced it would reconsider these 2008 ozone standards. The purpose of the reconsideration is to ensure that the ozone standards are clearly grounded in science, protect public health with an adequate margin of safety, and are sufficient to protect the environment. EPA proposed revisions to the standards on January 19, 2010 (75 FR 2938) and anticipates issuing final standards soon.

c. Which NAAQS does this rule address?

This action addresses the requirements of CAA section 110(a)(2)(D)(i)(I) as they relate to:

(1) The 1997 annual $PM_{2.5}$ standard,

(2) The 2006 24-hour $PM_{2.5}$ standard, and

(3) The 1997 ozone standard.

The original CAIR and CAIR FIP rules, which pre-dated the 2006 $PM_{2.5}$ standards, addressed the 1997 ozone and 1997 $PM_{2.5}$ standards only.

In this action, EPA fully addresses, for the states covered by this rule, the requirements of CAA section 110(a)(2)(D)(i)(I) for the annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and the 24-hour standard of 35 $\mu g/m^3$. For the 1997 8-hour ozone standard of 0.08 ppm, EPA fully addresses the CAA section 110(a)(2)(D)(i)(I) requirements for some states covered by this rule, but for the remaining states EPA is conducting further analysis to determine whether further requirements are needed, as discussed in section III of this preamble.

This action does not address the CAA section 110(a)(2)(D)(i)(I) requirements for the revised ozone standards promulgated in 2008. These standards are currently under reconsideration. We are, however, actively conducting the technical analyses and other work needed to address interstate transport for the reconsidered ozone standard as soon as possible. We intend to issue as soon as possible a proposal to address the transport requirements with respect to the reconsidered standard.

This action addresses these CAA transport requirements through reductions in annual emissions of SO_2 and NO_X, and through reductions in ozone-season NO_X. The rationale for these reductions is discussed in detail later in the preamble.

d. Public Comments

EPA received comments on two issues related to the NAAQS regulated under the proposed FIPs.

A number of commenters believed that EPA's approach to ozone was inadequate, and that EPA should not have based the proposed requirements on the 1997 ozone NAAQS. These commenters cited EPA's 2008 revision to the standard which lowered the standard to 75 ppb, and noted that EPA's January 2010 proposal for reconsidered ozone NAAQS would, if finalized, further lower the primary NAAQS from 75 ppb to a value between 60 and 70 ppb. Accordingly, many of the commenters believed that EPA should have considered the 75 ppb level to be the maximum possible value moving forward, and that EPA should have used a value no greater than 75 ppb in its analysis.

EPA agrees with commenters that EPA and states should address interstate transport with respect to the tighter

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ozone NAAQS as quickly as possible. EPA, as commenters noted, intends to propose a second rule to address interstate transport of ozone that will be appropriately configured for the revised level of the ozone NAAQS after reconsideration of the 2008 standard is finalized. EPA is mindful of the need for SIPs to provide for continuing ozone progress to meet the 75 ppb level of the 2008 NAAQS, or possibly lower levels based on the reconsideration. EPA believes that the ozone-season NO_X requirements of this rule will provide important initial assistance to states in this regard.

Some commenters questioned whether EPA had given states the opportunity to provide SIPs addressing transport under the 2006 $PM_{2.5}$ NAAQS, and thus questioned the appropriateness of the issuance of FIPs addressing those NAAQS. Those comments, and EPA's response, are discussed in detail in section IV.C.2.

2. FIP Authority for Each State and NAAQS Covered

The CAA requires and authorizes EPA to promulgate each of the Federal Implementation Plans in this final rule. Section 110(c)(1) of the CAA requires the Administrator to promulgate a FIP at any time within 2 years after the Administrator takes one of three distinct actions: (1) She finds that a state has failed to make a required SIP submission; (2) she finds a SIP submission to be incomplete; or (3) she disapproves a SIP submission. Once the Administrator has taken one of these actions with respect to a specific state's 110(a)(2)(D)(i)(I) obligation for a specific NAAQS, she has a legal obligation to promulgate a FIP to correct the SIP deficiency within 2 years. EPA is relieved of the obligation to promulgate a FIP only if two events occur before the FIP is promulgated: (1) The state submits a SIP correcting the deficiency; and (2) the Administrator approves the SIP revision. 42 U.S.C. 7410(c)(1).[11]

For each FIP in this rule,[12] EPA either has found that the state has failed to make a required 110(a)(2)(D)(i)(I) SIP submission, or has disapproved a SIP submission.[13] In addition, EPA has determined, in each case, that there has been no approval by the Administrator of a SIP submission correcting the deficiency prior to promulgation of the FIP. EPA's obligation to promulgate a FIP arose when the finding of failure to submit or disapproval was made, and in no case has it been relieved of that obligation.

Some commenters argued that EPA was relieved of its obligation to promulgate FIPs when it approved the CAIR SIPs for certain states. As an initial matter, EPA notes that this argument applies only to EPA's authority to promulgate FIPs with respect to the 1997 $PM_{2.5}$ and/or 1997 ozone NAAQS for a subset of states covered by the CAIR. It does not apply to EPA's authority to promulgate FIPs for the 2006 $PM_{2.5}$ NAAQS which was not addressed in CAIR. It also does not apply to EPA's authority to promulgate FIPs for the 1997 ozone and 1997 $PM_{2.5}$ NAAQS for states that remain subject to the CAIR FIPs, including the states that received EPA approval of abbreviated CAIR SIPs which allowed the states to allocate allowances while remaining subject to the CAIR FIPs.[14]

Further, the CAIR SIP approvals do not eliminate EPA's obligation and authority to promulgate a FIP to address the requirements of 110(a)(2)(D)(i)(I) because the Court in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008) found that compliance with CAIR does not satisfy the requirement that each state prohibit all emissions within the state that significantly contribute to nonattainment or interfere with maintenance in another state. The Court's finding that CAIR was unlawful because it did not make measureable progress towards the statutory mandate of section 110(a)(2)(D)(i)(I) meant that the CAIR SIPs were not adequate to satisfy that mandate. The CAIR SIPs thus do not correct the SIP deficiencies identified in the 2005 findings of failure to submit. The SIPs remained in force for the limited purpose allowed by the Court—that is, to achieve interim reductions until EPA promulgated a rule to replace CAIR. Given the flaws the court identified with CAIR, EPA's approval of a CAIR SIP does not relieve it of the obligation to promulgate FIPs created under section 110(c)(1) of the CAA.

Further, to avoid any confusion, EPA has decided to correct, in this notice, the full CAIR SIP approvals for states covered by this rule and the CAA 110(a)(2)(D)(i) SIP approvals for states covered by CAIR to rescind any statements suggesting that the SIP submissions satisfied or relieved states of the obligation to submit SIPs to satisfy the requirements of section 110(a)(2)(D)(i)(I) or that EPA was relieved of its obligation and authority to promulgate FIPs under 110(a)(2)(D)(I)(i).

Some commenters further argued that states should be given additional time, following promulgation of the Transport Rule, to submit a SIP to meet the requirements of section 110(a)(2)(D)(i)(I) and that CAIR should remain in place in the meantime. Some commenters specifically suggested that EPA restart the ''FIP clock'' [15] to give states this additional time. EPA does not interpret the CAA as giving it authority to extend the deadline for SIP submissions or restart the FIP clock. And nothing in the Act requires EPA to give the states another opportunity, following promulgation of the Transport Rule, to promulgate a SIP before EPA promulgates a FIP. The plain language of section 110(a)(1) of the Act requires the submission of SIPs that meet the requirements of 110(a)(2)(D)(i)(I) within 3 years after the promulgation of or revision of a primary NAAQS. *See* 42 U.S.C. 7410(a)(1). Section 110(a)(2)(D)(i)(I) SIPs for the 1997 ozone and $PM_{2.5}$ NAAQS were due in 2000 and 110(a)(2)(D)(i)(I) SIPs for the 2006 $PM_{2.5}$ NAAQS were due in 2009. While the statute gives EPA authority to prescribe a shorter period of time for states to make these SIP submissions, it does not give EPA authority to extend the 3-year deadline established by the Act. *See* 42 U.S.C. 7410(a)(1). The plain language of section 110(c)(1) of the Act, in turn, provides that EPA shall promulgate a FIP at any time within 2 years after the Administrator makes a finding of failure to make a required SIP

[11] The CAA provides that EPA is not relieved of its obligation to promulgate FIPs unless the state submits a SIP that corrects the deficiency and EPA approves the SIP. Nonetheless, in the preamble to the proposed rule, EPA indicated that for states not covered by CAIR which had 110(a)(2)(D)(i)(I) SIPs pending at the time of proposal, EPA would finalize the FIP only if EPA determined the submission was incomplete or disapproved the SIP submission. The only two states covered by this rule but not covered by CAIR are Kansas and Nebraska. Both Kansas and Nebraska are covered by this rule based only on their significant contribution to nonattainment or interference with maintenance of the 2006 $PM_{2.5}$ NAAQS. EPA has not received a 110(a)(2)(D)(i)(I) submission from Nebraska with respect to the requirements of the 2006 $PM_{2.5}$ NAAQS. EPA disapproved a SIP submission from Kansas with respect to the requirements of 110(a)(2)(D)(i)(I) for the 2006 $PM_{2.5}$ NAAQS.

[12] In this action, EPA is issuing 59 FIPs. EPA is issuing 20 FIPs to remedy SIP deficiencies relating to the 110(a)(2)(D)(i)(I) requirements for the 1997 ozone NAAQS. EPA is also issuing 18 FIPs to remedy SIP deficiencies relating to the 1997 $PM_{2.5}$ NAAQS. Finally, EPA is issuing 21 FIPs to remedy SIP deficiencies relating to the 2006 $PM_{2.5}$ NAAQS.

[13] The specific findings made and actions taken by EPA are described in greater detail in the TSD entitled ''Status of CAA 110(a)(2)(D)(i)(I) SIPs.''

[14] States may also have received approval to expand the applicability of the CAIR NO_X ozone season program to include all units subject to the NO_X Budget Program, allow opt-ins, or provide for distribution of a Compliance Supplement Pool under the CAIR NO_X (annual) program.

[15] ''FIP clock'' is a term used to describe EPA's responsibility found in CAA Section 110(c)(1) to promulgate a FIP within 2 years after either: Finding that a state has not submitted a required SIP revision or that a submitted SIP revision is incomplete; or disapproving a SIP revision.

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submission of disapproves, in whole or in part, a SIP submission. *See* 42 U.S.C. 7410(c)(1). EPA does not have authority to set aside the specific deadlines established in the statute, and neither provision allows for the deadlines to be extended or to run from promulgation by EPA of a rule to quantify the state's specific obligations pursuant to section 110(a)(2)(D)(i)(I). The Act does not require EPA to promulgate a rule or issue guidance regarding the specific requirements of section 110(a)(2)(D)(i)(I) in advance of the SIP submittal deadline, much less require EPA to promulgate such a rule a specific amount of time before the SIP submittal deadline. For these reasons, EPA has neither authority to alter the SIP submittal deadline nor authority to alter the statute provision regarding when EPA's obligation to promulgate a FIP is triggered.

Finally, EPA does not believe it would be appropriate, in light of the Court's decision in *North Carolina,* to establish a lengthy transition period to the rule that will replace CAIR. The Court decision remanding CAIR without vacatur stressed the court's conclusion that CAIR was deeply flawed and emphasized EPA's obligation to remedy those flaws expeditiously. *North Carolina,* 550 F.3d 1176. Although the Court did not set a specific deadline for corrective action, the Court took care to note that the effect of its opinion would not be delayed ''indefinitely'' and that petitioners could bring a mandamus petition if EPA were to fail to modify CAIR in a manner consistent with its prior opinion. *Id.* Given the Court's emphasis on remedying CAIR's flaws expeditiously, EPA does not believe it would be appropriate to establish a lengthy transition period to the rule which is to replace CAIR.

3. Additional Information Regarding CAA Section 110(a)(2)(D)(i)(I) SIPs for States in the Transport Rule Modeling Domain

This final rule quantifies out-of-state contributions for the 38 states that are fully contained within the 12 kilometers (km) eastern U.S. modeling domain. EPA is making no specific finding for states that are not fully contained within the eastern 12 km modeling domain. EPA did not conduct a contribution analysis or make any specific finding for New Mexico, Colorado, Wyoming, and Montana since they are only partially contained within the 12 km modeling domain. With regard to the 1997 $PM_{2.5}$ NAAQS and 2006 $PM_{2.5}$ NAAQS, EPA believes that states that are included in this 38 state modeling domain will meet their section 110(a)(2)(D)(i)(I) obligations to address the ''significant contribution'' and ''interference with maintenance'' requirements by complying with the requirements in this rule. With regard to the 1997 ozone NAAQS, EPA believes that states that are included in this 38 state modeling domain will meet their section 110(a)(2)(D)(i)(I) obligations to address the ''significant contribution'' and ''interference with maintenance'' requirements by complying with the requirements in this rule, except for the 10 states found to significantly contribute to nonattainment or interference of maintenance in either Houston or Baton Rouge (*i.e.,* Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Tennessee, and Texas). States that are in the 38 state modeling domain, and that are not found to be contributing significantly to nonattainment or interfering with maintenance for any NAAQS evaluated in the modeling for the final rule, could rely on this analysis as technical support that their existing or future interstate transport SIP submittals are adequate to address the transport requirements of 110(a)(2)(D)(i)(I). For example, this rule finds that South Carolina significantly contributes to nonattainment and interferes with maintenance of the 1997 ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS in downwind states. The technical support for the rule does not show that South Carolina significantly contributes to nonattainment or interferes with maintenance of the 2006 $PM_{2.5}$ NAAQS in downwind states. EPA believes that South Carolina can make a negative declaration concluding that the state does not significantly contribute to nonattainment or interfere with maintenance in other states with regard to the 2006 $PM_{2.5}$ NAAQS.

D. Correction of CAIR SIP Approvals

In this action, EPA is also correcting its prior approvals of CAIR related SIP submissions and CAA 110(a)(2)(D)(i) SIP submissions from Alabama, Arkansas, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Virginia and West Virginia to rescind any statements that the SIP submissions either satisfy or relieve the state of the obligation to submit a SIP to satisfy the requirements of section 110(a)(2)(D)(i)(I) with respect to the 1997 ozone and/or 1997 $PM_{2.5}$ NAAQS or any statements that EPA's approval of the SIP submissions either relieve EPA of the obligation to promulgate a FIP or remove EPA's authority to promulgate a FIP. This action is based on EPA's determination that those SIP approvals were in error to the extent they provided explicitly or implicitly that compliance with CAIR satisfies the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone and 1997 $PM_{2.5}$ NAAQS. The July 2008 decision of the DC Circuit held, among other things, that the CAIR rule did not ''achieve[] something measureable toward the goal of prohibiting sources 'within the State' from contributing to nonattainment or interfering with maintenance in 'any other State.''' *North Carolina,* 531 F.3d 908; see also, *e.g., id.* at 916 (EPA not exercising its authority to make measureable progress towards the goals of section 110(a)(2)(D)(i)(I) because the emission budgets were insufficiently related to the statutory mandate). EPA's actions to approve CAIR SIP submittals as satisfying the requirements of section 110(a)(2)(D)(i)(I), based on the flawed determination in CAIR that compliance with CAIR satisfied those statutory requirements, were thus in error as were the separate actions taken to approve section 110(a)(2)(D)(i)(I) submissions that relied wholly or in part on CAIR.

The approval for Alabama titled ''Approval and Promulgation of Implementation Plans; Alabama; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 1, 2007 (72 FR 55659).

The approval for Arkansas titled ''Approval and Promulgation of Implementation Plans; Arkansas; Clean Air Interstate Rule Nitrogen Oxides Ozone Season Trading Program'' which is hereby corrected was originally published in the **Federal Register** on September 26, 2007 (72 FR 54556).

The approval for Connecticut titled ''Approval and Promulgation of Air Quality Implementation Plans; Connecticut; State Implementation Plan Revision to Implement the Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on January 24, 2008 (73 FR 4105) and the approval for Connecticut titled ''Approval and Promulgation of Air Quality Implementation Plans; Connecticut; Interstate Transport of Pollution'' which is hereby corrected was originally published in the **Federal Register** on May 7, 2008 (73 FR 25516).

The approval for Florida titled ''Approval and Promulgation of Implementation Plans; Florida; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 12, 2007 (72 FR 58016).

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The approval for Georgia titled ''Approval and Promulgation of Implementation Plans; Georgia; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 9, 2007 (72 FR 57202).

The approval for Illinois titled ''Approval of Implementation Plans of Illinois: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 16, 2007 (72 FR 58528).

The approval for Indiana titled ''Limited Approval of Implementation Plans of Indiana: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 22, 2007 (72 FR 59480) and the approval for Indiana titled ''Approval and Promulgation of Air Quality Implementation Plans; Indiana; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on November 29, 2010 (75 FR 72956).

The approval for Iowa titled ''Approval and Promulgation of Implementation Plans; Iowa; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on August 6, 2007 (72 FR 43539) and the approval for Iowa titled ''Approval and Promulgation of Implementation Plans; Iowa; Interstate Transport of Pollution'' which is hereby corrected was originally published in the **Federal Register** on March 8, 2007 (72 FR 10380).

The approval for Kentucky titled ''Approval of Implementation Plans of Kentucky: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 4, 2007 (72 FR 56623).

The approval for Louisiana titled ''Approval and Promulgation of Implementation Plans; Louisiana; Clean Air Interstate Rule Sulfur Dioxide Trading Program'' which is hereby corrected was originally published in the **Federal Register** on July 20, 2007 (72 FR 39741) and the approval for Louisiana titled ''Approval and Promulgation of Implementation Plans; Louisiana; Clean Air Interstate Rule Nitrogen Oxides Trading Program'' which is hereby corrected was originally published in the **Federal Register** on September 28, 2007 (72 FR 55064).

The approval for Maryland titled ''Approval and Promulgation of Air Quality Implementation Plans; Maryland; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 30, 2009 (74 FR 56117).

The approval for Massachusetts titled ''Approval and Promulgation of Air Quality Implementation Plans; Massachusetts; State Implementation Plan Revision to Implement the Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on December 3, 2007 (72 FR 67854).

The approval for Minnesota titled ''Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Interstate Transport of Pollution'' which is hereby corrected was originally published in the **Federal Register** on June 2, 2008 (73 FR 31366).

The approval for Mississippi titled ''Approval and Promulgation of Implementation Plans; Mississippi: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 3, 2007 (72 FR 56268).

The approval for Missouri titled ''Approval and Promulgation of Implementation Plans; Missouri; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on December 14, 2007 (72 FR 71073) and the approval of Missouri titled ''Approval and Promulgation of Implementation Plans; Missouri; Interstate Transport of Pollution'' which is hereby corrected was originally published in the **Federal Register** on May 8, 2007 (75 FR 25975).

The approval for New York titled ''Approval and Promulgation of Implementation Plans; New York: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on January 24, 2008 (73 FR 4109).

The approval for North Carolina titled ''Approval of Implementation Plans; North Carolina: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 5, 2007 (72 FR 56914) and the approval for North Carolina titled ''Approval and Promulgation of Air Quality Implementation Plans; North Carolina; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on November 30, 2009 (74 FR 62496).

The approval for Ohio titled ''Approval and Promulgation of Air Quality Implementation Plans; Ohio; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on February 1, 2008 (73 FR 6034) and the approval for Ohio titled ''Approval and Promulgation of Air Quality Implementation Plans; Ohio; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on September 25, 2009 (74 FR 48857).

The approval for Pennsylvania titled ''Approval and Promulgation of Air Quality Implementation Plans; Pennsylvania; Clean Air Interstate Rule; NO_X SIP Call Rule; Amendments to NO_X Control Rules'' which is hereby corrected was originally published in the **Federal Register** on December 10, 2009 (74 FR 65446).

The approval for South Carolina titled ''Approval of Implementation Plans of South Carolina: Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 9, 2007 (72 FR 57209) and the approval for South Carolina titled ''Approval and Promulgation of Air Quality Implementation Plans; South Carolina; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on October 16, 2009 (74 FR 53167).

The approval for Virginia titled ''Approval and Promulgation of Air Quality Implementation Plans; Virginia; Clean Air Interstate Rule Budget Trading Programs'' which is hereby corrected was originally published in the **Federal Register** on December 28, 2007 (72 FR 73602).

The approval for West Virginia titled ''Approval and Promulgation of Air Quality Implementation Plans; West Virginia; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on December 18, 2007 (72 FR 71576) and the approval for West Virginia titled ''Approval and Promulgation of Air Quality Implementation Plans; West Virginia; Clean Air Interstate Rule'' which is hereby corrected was originally published in the **Federal Register** on August 4, 2009 (74 FR 38536).

EPA is taking this final action without prior opportunity for notice and comment because EPA finds, for good cause, that notice and public procedure thereon are unnecessary and not in the public interest. Section 553(b)(B) of the Administrative Procedure Act provides that the notice and comment requirements in section 553 do not apply when the agency for good cause finds that notice and public procedure there on are impracticable, unnecessary, or contrary to the public interest. 5 U.S.C. 553(b)(B). Section 307(d)(1) of the CAA in turn provides that the requirements of section 307(d) do not apply in the case of a rule or circumstance referred to in section 553(b)(A) or section 553(b)(B) of the Administrative Procedure Act in Title 5. 42 U.S.C. 7607(1).

EPA finds that notice and public procedure are unnecessary because EPA has no discretion given the specific

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circumstances presented in this case. EPA is bound by the decisions of the courts and must act in accordance with those decisions. EPA must accept the Court's conclusion that compliance with CAIR does not satisfy the requirements of CAA section 110(a)(2)(D)(i)(I) and lacks discretion to reach a different conclusion. This correction is a ministerial matter consistent with the decisions of the courts. For these reasons, it is unnecessary to provide an opportunity for notice and comment.

V. Analysis of Downwind Air Quality and Upwind State Emissions

A. Pollutants Regulated

To address interstate transport of air pollution, EPA must choose which pollutants to regulate relevant to significant contribution to nonattainment or interference with maintenance of the NAAQS of concern downwind. This section of the preamble discusses the pollutants regulated under the final Transport Rule.

1. Background

Based on scientific and technical information, as well as EPA's air quality modeling, EPA concluded for CAIR that the most effective approach to reducing the contribution of interstate transport to $PM_{2.5}$ was to control SO_2 and NO_X emissions. For CAIR, EPA did not limit emissions of other components of $PM_{2.5}$, noting that ''current information relating to sources and controls for other components identified in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components'' (69 FR 4582).

With respect to ozone transport, EPA has previously concluded that it is proper to control ozone-season NO_X emissions. For CAIR and the NO_X SIP Call programs, EPA based this conclusion on the assessment of ozone transport conducted by the Ozone Transport Assessment Group (OTAG) in the mid-1990s. The OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups concluded that regional NO_X emission reductions are effective in producing ozone benefits that grow with increasing regional NO_X abatement.

The relative importance of NO_X and VOC in ozone formation and control varies with local and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas and many urban areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind. The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature also increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.,* increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large scale stagnation of air masses, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. Authoritative assessments of ozone control approaches have concluded that, for reducing regional scale ozone transport, a NO_X control strategy is most effective, whereas VOC reductions are generally most effective locally, in more dense urbanized areas.

Studies conducted since the 1970s established that ozone occurs on a regional scale (*i.e.,* thousands of kilometers) over much of the eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas. While substantial progress has been made in reducing ozone in many urban areas, regional-scale ozone transport is still an important component of high ozone concentrations during the extended summer ozone season. A series of more recent progress reports discussing the effect of the NO_X SIP Call reductions can be found on EPA's Web site at: *http://www.epa.gov/airmarkets/progress/progress-reports.html.*

More recent assessments of ozone (including those conducted for the Regulatory Impact Analysis for the ozone standards in 2008) continue to show the importance of NO_X transport as a factor in ozone formation. For addressing interstate ozone transport in CAIR, EPA required NO_X emission reductions but did not include requirements for VOCs. EPA believes that VOCs from some upwind states do indeed have an impact in some nearby downwind states, particularly over short transport distances. EPA expects that states, typically in local nonattainment planning, would benefit from examining the extent to which VOC emissions affect ozone pollution levels within and near urban nonattainment areas, and states may identify areas where multi-state VOC strategies might assist in attainment planning for meeting the 8-hour standard. However, EPA continues to believe that the most effective regional pollution control strategy for mitigation of interstate transport of ozone remains NO_X emission reductions.

2. Which pollutants did EPA propose to control for purposes of $PM_{2.5}$ and ozone transport?

For the proposed rule, EPA concluded that its findings in CAIR regarding the nature of pollutant contributions are still appropriate. EPA proposed to require SO_2 and annual NO_X emission reductions to control $PM_{2.5}$ transport and to require ozone-season NO_X emission reductions to control ozone transport. In the proposal, EPA discussed and requested comment on the inclusion of southern states in the annual NO_X program for $PM_{2.5}$ control.

3. Comments and Responses

EPA received no adverse comments on its proposal to regulate SO_2 for addressing $PM_{2.5}$ transport, the proposal not to regulate direct $PM_{2.5}$ or organic $PM_{2.5}$ precursors, and the proposal to focus ozone-season efforts on NO_X and not to regulate VOCs.

One commenter questioned EPA's regulation of NO_X for purposes of addressing $PM_{2.5}$ transport in all states (including northern states with cooler climates and higher nitrate deposition). Several commenters, representing southern state air quality agencies and regulated sources in southern states, disagreed with EPA's proposed regulation of annual NO_X emissions for all regulated states. These commenters, while not disagreeing with the need for regulation of SO_2, observed that in EPA's modeling analysis, contributions from certain southern states' NO_X emissions to $PM_{2.5}$ in downwind states were relatively small.

Accordingly, these commenters argued that either (1) EPA should remove NO_X as a precursor analyzed for $PM_{2.5}$ contribution from those states, or (2) the required remedy for emission reductions in those states should not require reductions in annual NO_X.

For the final rule, EPA retains the approach for regulated pollutants in the proposal, which regulates annual NO_X and SO_2 for states affecting downwind state $PM_{2.5}$ nonattainment and maintenance sites, and ozone-season NO_X for states impacting downwind state ozone nonattainment and maintenance. EPA considered commenters' requests to remove some states from the annual NO_X program. However, EPA believes that it is

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appropriate to establish a cap on these states' annual NO_X emissions, in part to ensure the continued annual operation of existing control equipment that would prevent substantial increases in NO_X emissions. EPA believes that without these reductions, increased ''nitrate replacement'' could occur, a known atmospheric phenomenon whereby some of the sulfate reductions due to SO_2 emission reductions are eroded by increases in nitrate concentrations due solely to those SO_2 reductions.[16] This is an especially pertinent concern for southern states which have significant impacts on northern receptors in colder climates where nitrate concentrations are generally higher. For example, Alabama and Tennessee are both linked to Washtenaw County, MI for 24-hour $PM_{2.5}$; North Carolina is linked to Lancaster County, PA for 24-hour $PM_{2.5}$; and Texas is linked to Madison County, IL for both annual and 24-hour $PM_{2.5}$. All of these downwind areas have appreciable nitrate deposition contributing to nonattainment and maintenance concerns for the $PM_{2.5}$ NAAQS. If the states linked to those receptors were to make SO_2 reductions only, their beneficial impact on downwind air quality would be partially eroded by nitrate replacement. EPA therefore believes that it is reasonable to seek both SO_2 and NO_X reductions from states included in the Transport Rule program that are found to significantly contribute to nonattainment or interfere with maintenance of the $PM_{2.5}$ NAAQS in downwind states.

In addition, EPA notes that there would be important disbenefits to effectively removing CAIR's existing annual NO_X requirements in those states. If EPA were to allow annual NO_X emissions to increase for those states, there would be potentially harmful effects on visibility, nitrogen deposition, and other aspects of human and environmental health.

B. Baseline for Pollution Transport Analysis

Implementing the mandate of CAA section 110(a)(2)(D)(i)(I) requires EPA to determine which states significantly contribute to nonattainment and interfere with maintenance of the NAAQS in other states, as well as to quantify the emissions in each state that must be eliminated. This process begins with an analysis of baseline emissions. Baseline emissions are the emissions that would occur in each state if EPA did not promulgate the Transport Rule. To conduct such analysis, EPA generally takes into account emission limitations that are currently, and will continue to be, in place. From that baseline, EPA analyzes whether additional reductions are necessary beyond those already mandated by existing emission limitation requirements. For example, the base case used in CAIR reflected the reductions already required by the NO_X SIP Call, which remained in effect even after the CAIR emission reduction requirements took effect.

The unique legal situation addressed by the Transport Rule necessarily affects the quantification of baseline emissions. Specifically, because the Transport Rule will replace CAIR, EPA cannot consider reductions associated with CAIR in the ''base case'' (*i.e.,* analytical baseline emissions scenario). If EPA were to consider all reductions associated with CAIR in the ''base case,'' the baseline emissions would not adequately reflect the true 2012 baseline in each state (*i.e.,* the emissions that would occur in each state in 2012 if the Transport Rule did not require any reductions in that state). Similarly, if EPA were to treat the capital investments that have already been made to meet the requirements of CAIR as new costs rather than treating them as ''sunk'' capital costs, EPA's analysis would not accurately reflect the cost of emission reductions required by the Transport Rule. As explained below, EPA's analysis both properly considered all capital investments made in response to CAIR and properly recognized that, after CAIR is terminated, the emission limitations imposed by CAIR will cease to exist.

In 2005 EPA promulgated CAIR, which required large electric generating units in 29 states to make phase I emission reductions in NO_X emissions starting in 2009, phase I emission reductions in SO_2 starting in 2010 and phase II reductions in emissions of both pollutants starting in 2015. On July 11, 2008, the DC Court of Appeals held that CAIR had ''more than several fatal flaws,'' *North Carolina,* 531 F.3d at 901, and remanded and vacated the rule, *id.* at 930. The Court subsequently granted EPA's petition for rehearing in part and remanded CAIR without vacatur ''for EPA to conduct further proceedings consistent with'' the Court's July 11, 2008 opinion. *North Carolina,* 550 F.3d 1176. The Court explained that it was ''allowing CAIR to remain in effect until it is replaced by a rule consistent with [the July 11, 2008] opinion'' because this ''would at least temporarily preserve the environmental values covered by CAIR.'' *Id.* at 1178. Moreover, the Court stated that it did not ''intend to grant an indefinite stay of the effectiveness of'' the July 11, 2008 order vacating CAIR. *Id.* In summary, the Court determined that CAIR was fatally flawed and could remain in effect only as a stopgap measure until EPA could act to replace it.

Thus, unlike most other regulatory requirements (such as the Acid Rain Program under CAA Title IV, the NO_X Budget Trading Program under the NO_X SIP Call, New Source Performance Standards, and state laws and consent orders requiring emission reductions), the emission limitations contained in CAIR are only temporary. Moreover, the duration of these limitations is directly tied to the Transport Rule. The Transport Rule replaces CAIR. Thus, CAIR itself will be terminated for the SO_2, annual NO_X, and ozone-season NO_X control periods starting in 2012 when the emission limitations established in the final Transport Rule for those control periods take effect (January 1, 2012 for the annual control periods and May 1, 2012 for the ozone-season control period). For this reason, emission reductions made to comply with CAIR cannot be treated as if they were emission reductions achieved to comply with statutory provisions, rules, consent decrees, and other enforceable requirements that establish permanent emission limitations. EPA takes reductions made to comply with permanent limitations into consideration when quantifying each state's baseline emissions for the purpose of analyzing whether its emissions significantly contribute to nonattainment or interfere with maintenance in another state. However, the unique legal status of CAIR and its replacement with the Transport Rule distinguish the emission reductions required by CAIR from those of other regulatory requirements. Since the limitations and emission reduction requirements in CAIR are temporary and will be terminated by the Transport Rule, they must be excluded from the Transport Rule's base case analysis.

Some comments on the Transport Rule proposal claim that EPA's treatment of CAIR is inconsistent with the treatment, in prior rulemakings, of the Acid Rain Program and the NO_X SIP Call. Such comments ignore the unique legal status of CAIR, and EPA therefore rejects these claims.

A simple example illustrates this point. Assume state Z's emissions before

[16] SO_2 reductions successfully decrease atmospheric formation of ammonium sulfate, but in doing so they ''free up'' the ammonia component that would otherwise have reacted with SO_2 and is now free to react with NO_X instead, causing a ''rebound effect'' partially eroding the improvement in $PM_{2.5}$ concentrations. This effect can be mitigated with tandem NO_X reductions.

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CAIR were 2,000 tons and that state Z was required by CAIR to reduce its emissions to 1,000 tons. If EPA were to determine that state Z's baseline emissions were 1,000 tons and then conclude, based on that assumption, that no additional reductions in state Z are necessary because state Z does not significantly contribute to downwind nonattainment unless its emissions exceed 1,500 tons, then state Z would not be covered by the Transport Rule. However, the Transport Rule will terminate all CAIR requirements in all CAIR states regardless of whether they are covered by the Transport Rule. Thus, after promulgation of the Transport Rule, state Z would again be allowed, and would be projected in this example, to emit 2,000 tons. In other words, state Z would be allowed to significantly contribute to nonattainment and/or interfere with maintenance in other states—a result that would be inconsistent with the statutory mandate of CAA section 110(a)(2)(D)(i)(I). On the other hand, if EPA assumes state Z's baseline emissions are 2,000 tons as projected without CAIR in place, EPA can properly determine whether, if state Z were allowed to emit that amount (*i.e.,* the amount state Z would be projected to emit if excluded from the Transport Rule), the state would significantly contribute to nonattainment or interfere with maintenance in any other state. In other words, EPA can determine the stringency of emission limitations needed (if any) to replace those that were established by CAIR in order to ensure that state Z prohibits all emissions that significantly contribute to nonattainment or interfere with maintenance in other states.

In fact, commenters' suggestion that the Transport Rule base case should include CAIR would cause the anomalous result of excluding sources in a state from the Transport Rule because of their CAIR–required emission reductions while simultaneously eliminating those CAIR emission reduction requirements. If EPA's base case analysis were to assume erroneously that reductions from CAIR would continue indefinitely, a state currently covered by CAIR, but not covered by the Transport Rule, would have no CAIR requirements once the Transport Rule programs began and so could increase emissions beyond the CAIR limitations. Downwind areas that are in attainment (and are not experiencing interference with maintenance of such attainment) solely because of emission reductions required by CAIR could again face nonattainment or interference with maintenance problems because the current protection from upwind pollution from such an upwind state would not be replaced. In short, the analysis of whether a state should be included in a rule eliminating and replacing CAIR cannot logically assume that CAIR remains in place. For these reasons, EPA believes it is reasonable to use a base case that does not assume that the CAIR reduction requirements will continue to be achieved and so does not include CAIR-specific emission reductions.

As a result, EPA's 2012 base case shows emissions higher than current levels in some states. In the absence of the CAIR SO_2 and NO_X programs that EPA has been directed to eliminate and replace, utility emissions in CAIR states will be limited only by non-CAIR constraints including the Acid Rain Program, the NO_X SIP Call, New Source Performance Standards, any state laws and consent order requiring emission reductions, and any other permanent and enforceable binding reduction commitments. This will lead to increased emissions in some states in the 2012 base case relative to current emissions. For example, efforts to comply with the Acid Rain Program at the least cost may occur, in some cases, without the operation of existing scrubbers through use of readily available, inexpensive Title IV allowances.

It is important to note that, to the extent that emission reductions currently required by CAIR are also reflected in emission reduction requirements under the Acid Rain Program, the NO_X SIP Call, New Source Performance Standards, any state laws and consent orders requiring emission reductions, and any other enforceable binding reduction commitments, such reductions are accounted for in EPA's 2012 base case. Some commenter claimed that in excluding CAIR-specific emission reductions from the base case, EPA ignores non-CAIR legal requirements (*e.g.,* in Title V permits) that may prevent sources from increasing emissions above CAIR levels. Such allegations are incorrect. As discussed elsewhere in this preamble, EPA accounted for any Title V permits, consent decrees, state rules, and other enforceable limitations on sources' emissions; if these non-CAIR limitations effectively restrain a state's emissions to not exceed the state's CAIR limitations, EPA's base case modeling would reflect this outcome. Commenters also assert that utilities are unlikely to dismantle or discontinue running the installed controls to the point of returning to pre-CAIR emission levels. EPA agrees that installed controls are not likely to be physically dismantled, and as discussed elsewhere in this preamble, EPA's analysis properly treats the capital investments made in emission controls attributed to CAIR as ''sunk'' capital costs (*i.e.,* capital costs already obligated in the past) that are not included as costs of meeting Transport Rule requirements.

Our cost analysis for significant contribution reflects on-the-ground realities. Investments in pollution control equipment were made in response to CAIR requirements. Those expenditures are ''sunk'' capital costs, meaning that those investments were committed in the past, prior to the Transport Rule. Adding the capital costs of that equipment into the costs of Transport Rule emission reduction options would be incorrect; those capital investments are represented in place in the base case.

However, given ongoing costs associated with operating these controls, EPA believes sources would have an economic incentive to discontinue operating installed controls, or to operate those controls less effectively, except to the extent non-CAIR legal requirements mandate emission reductions or to the extent that sources would find it economic to operate the controls for non-CAIR market-based emission control programs. EPA properly treats the costs of operating controls installed to meet CAIR requirements as costs of meeting Transport Rule requirements.[17] EPA's base case accounts for non-CAIR requirements and does not make the unreasonable assumption that installed controls would be operated to achieve emission reductions that are not necessary to meet non-CAIR requirements. For all of these reasons, EPA rejects commenters' claims that the base case is ''unrepresentative'' or lacks ''a rational relationship to the real world.''

C. Air Quality Modeling To Identify Downwind Nonattainment and Maintenance Receptors

1. Emission Inventories

To inform air quality modeling for the development of the final Transport Rule, EPA developed emission

[17] For more details on how EPA models economic operation of existing pollution control equipment in the Transport Rule base case, please see Section 6 (''Dispatchable Controls'') in ''Updates to EPA Base Case v3.02 EISA Using the Integrated Planning Model'' Technical Support Document (TSD) for the Transport Rule Docket ID No. EPA–HQ–OAR– 2009–0491, U.S. EPA, July 2010 (available at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/IPM Update Documentation.pdf*).

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inventories for a 2005 base year and for 2012 and 2014 projections. The inventories for all years include emission estimates for EGUs, non-EGU point sources, stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, and biogenic (non-human) sources. EPA's air quality modeling relies on this comprehensive set of emission inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements. In addition, EPA considers all relevant emissions (regardless of source category) when determining whether a state is found to be significantly contributing to or interfering with maintenance of a particular NAAQS in another state.

The emission inventories were processed through the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 2.6 to produce the gridded, hourly, speciated, model-ready emissions for input to the CAMx air quality model. Additional information on the development of the emission inventories and related data sets for emissions modeling are provided in the Emission Inventory Final Transport Rule TSD.

On October 27, 2010, EPA issued a NODA on ''Revisions to Emission Inventories.'' The NODA's primary purpose was to notify the public about changes to emission inventories made since the proposal modeling. The affected emission sectors were non-EGU stationary point sources, nonpoint sources, and Category 3 commercial marine vessel sources. The NODA also presented a newly released model for developing onroad mobile source emissions for use in air quality modeling for the final Transport Rule.

The major comments received in response to the emission inventories and modeling included in the proposed Transport Rule and the October 27 NODA are summarized in the following subsections. EPA agreed with the comments summarized below and adopted technical corrections or updates to the emission inventories and modeling accordingly. For EPA to be able to take appropriate action, comments on the emission inventories needed to be specific enough to allow for credible alternative data sources to be located. EPA adopted corrections from comments on in-place control programs or devices where the controls were enforceable and quantifiable.

a. Foundation Emission Inventory Data Sets

EPA developed emission data representing the year 2005 to support air quality modeling of a base year from which future air quality could be forecasted. EPA used the 2005 National Emission Inventory (NEI), version 2 from October 6, 2008, as the chief basis for the U.S. inventories supporting the 2005 air quality modeling. This inventory includes 2005-specific data for point and mobile sources, while most nonpoint data were carried forward from version 3 of the 2002 NEI. The future base case scenarios modeled for 2012 and 2014 represent predicted emission reductions primarily from already promulgated federal measures.

EPA used a 2006 Canadian inventory and a 1999 Mexican inventory for the portions of Canada and Mexico within the air quality modeling domains for all modeled scenarios. Emissions from Canada and Mexico for all source sectors (including EGUs) in these countries were held constant for all base- and future-year cases. EPA made this assumption because it does not currently have sufficient data to support projections of future-year emissions from Canada and Mexico.

b. Development of Emission Inventories for EGUs

The annual NO_X and SO_2 emissions for EGUs in the 2005 NEI v2 are based primarily on data from continuous emissions monitoring systems (CEMS), with other EGU pollutants estimated using emission factors and annual heat input data reported to EPA. Although only NO_X and SO_2 are considered for control in this rule, emissions for all criteria air pollutants are necessary to model air quality. For EGUs without CEMS, EPA used data submitted to the NEI by the states. For more information on the details of how the 2005 EGU emissions were developed, see the Emissions Inventory Final Rule TSD.

Commenters stated that some point sources that were classified as non-EGUs in the proposal modeling were actually EGUs, resulting in double counting of emissions in future-year modeling. EPA reviewed its assignment of EGUs and non-EGUs and reclassified EGU sources found to be in the non-EGU inventory for the updated 2005 EGU inventory to prevent double counting of future-year emissions.

The future base case scenarios for EGUs reflect projected changes to fuel usage and economics, as described in the Emission Inventory Final Rule TSD. Future year base case EGU emissions that predict SO_2, NO_X, and $PM_{2.5}$ were obtained from version 4.10_FTransport of the Integrated Planning Model (IPM) outputs (*http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html*). The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector; version 4.10_FTransport reflects state rules and consent decrees through December 1, 2010, and incorporates public comments on existing controls submitted to EPA through both the Transport Rule-related notice and comment process as well as the proposed Mercury and Air Toxics Standards Information Collection Request (ICR). The operation of existing SO_2 or NO_X advanced controls (*e.g.,* scrubber, SCR) on units that were not required to operate those controls for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules was projected by IPM on the basis of providing least cost operation of the power generation system subject to existing regulatory requirements except CAIR (see baseline discussion in section V.B).

Additionally, IPM v.4.10_FTransport incorporates comments received during the rulemaking process. Fuel-related updates include comment-driven unit-specific limitations on 2012 coal rank selection, limiting unrestricted switching from bituminous to subbituminous coal by imposing boiler modification costs for those units shifting from bituminous to subbituminous coal without historical precedent, and a correction of waste coal prices. Pollution control-related updates include keying the performance assumptions for FGD and SCR more closely to historic performance data, and the inclusion of dry sorbent injection (DSI), a SO_2 removal technology. Other notable updates include revised assumptions on the heat rate and consequent dispatching of cogenerating units and incorporation of additional planned retirements. Further details on these updates are available in the IPM Documentation, available in the docket and at: *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

c. Development of Emission Inventories for Non-EGU Point Sources

Details on the development of emission inventories are available in the Emission Inventory Final Rule TSD. In both the proposal and final modeling, controls on industrial boilers installed under the NO_X SIP call were assumed to have been implemented by 2005 and captured in the 2005 NEI v2. The non-EGU point source emissions were updated from the 2005 NEI and the

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emissions used for the proposal modeling through the incorporation of comments on the proposal emissions values, previously unknown facility closures, and through other data improvements as identified by EPA analyses.

EPA does not factor in economic growth to develop non-EGU point source emission projections because analysis of historical emission trends and economic data did not support using economic growth to project non-EGU emissions. More details on the rationale for not applying economic growth to non-EGU industrial sources can be found in Appendix D of the Regulatory Impact Assessment (RIA) for the PM NAAQS rule (*http://www.epa.gov/ttn/ecas/regdata/RIAs/Appendix%20D – Inventory.pdf*). Although projections based on economic growth were not included, EPA did include reductions resulting from plant and unit closures, local and federal consent decrees, and several Maximum Achievable Control Technology (MACT) standards.

For non-EGU point sources, local control programs that may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are only included in the future base case projections when specific information about existing enforceable local controls was provided.

Since aircraft at airports were treated as point emissions sources in the 2005 NEI v2, we applied projection factors based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast (TAF) system, published in December 2008.

A number of comments were received on the stationary non-EGU point source inventories. Below is a summary of the major comments that impacted the stationary non-EGU point source inventories for the final modeling:

Comment: Commenters stated that EPA did not properly represent some point source emissions in base-year and future-year inventories due to facility and unit closures, consent decrees, emission caps, control programs, and alternative emission estimates.

Response: EPA reviewed the sources referenced in the individual comments regarding the base-year and future-year inventories. In cases where credible alternative data were available, EPA revised the emission inventories to incorporate additional facility and unit closures, consent decrees, emission caps, control programs, enforceable local controls, and alternative emission estimates.

Comment: Commenters stated that EPA should include controls from the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE NESHAP) in our modeling.

Response: EPA included reductions expected to be achieved by the RICE NESHAP across the United States in our final modeling of stationary non-EGU and nonpoint sources.

Comment: Commenters stated that EPA was not properly representing existing or planned controls for cement plants.

Response: EPA updated control and projection information for cement plants based on the latest available data and cement sector-specific modeling results.

Comment: EPA specifically requested comments on whether to incorporate emission reduction estimates from the NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (75 FR 32006). Commenters stated that emission reduction estimates should not be included until the rule became final.

Response: EPA did not incorporate emission reduction estimates from the NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (75 FR 32006) into the proposal or final modeling because the rule was not final at the time the modeling was performed. Note that reductions from this rule would not have impacted the 2012 base case due to its implementation schedule, and only the 2014 emissions would have been affected.

d. Development of Emission Inventories for Onroad Mobile Sources

The onroad emissions in the proposal modeling were primarily based on the National Mobile Inventory Model (NMIM) monthly, county, and process level emissions along with gasoline exhaust emissions from a fall 2008 draft version of the Motor Vehicle Emission Simulator (MOVES). A major comment on the proposal modeling for onroad mobile sources was the following:

Comment: Commenters stated that EPA should use a publicly released version of MOVES for its final modeling.

Response: EPA updated the final modeling to use data from the publicly released version of the MOVES 2010 model because the model became available in time for inclusion of its results in the final modeling. It was not used for the proposal modeling because it was not available at the time the modeling was performed.

In the final Transport Rule modeling, EPA used MOVES 2010 state-month level emissions for all criteria pollutants and all modes (evaporative, exhaust, brake wear and tire wear) and allocated those emissions to counties according to state-county NMIM emissions ratios. For California (the emissions for which are included to support the coarse modeling domain), the onroad mobile emissions data were derived from data provided by the state. These data were augmented with MOVES 2010 outputs for NH_3 because data for that pollutant had not been provided. Additional information on the approach to onroad mobile source emissions is available in the Emission Inventory Final Rule TSD.

In the future-year base modeling for mobile sources, all national measures available at the time of modeling were included. The future scenarios for mobile sources reflect projected changes to fuel usage, as described in the Emission Inventory Final Rule TSD. Emissions for these years reflect onroad mobile control programs including the Light-Duty Vehicle Tier 2 Rule, the Onroad Heavy-Duty Rule, the Light-Duty Vehicle Greenhouse Gas Rule, the Renewable Fuel Standards Rule, and the Mobile Source Air Toxics (MSAT) final rule.

e. Development of Commercial Marine Category 3 Vessel Emission Inventories

For the 2005 modeling, the commercial marine category 3 (C3) vessel emissions, a portion of nonroad mobile emissions, were augmented with gridded 2005 emissions from the previous modeling efforts for the rule called ''Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder.'' Emissions out to 200 nautical miles from the coastline were allocated to states in the proposal modeling. A major comment on the proposal modeling was the following:

Comment: Commenters stated that emissions from commercial marine sources (a component of the nonroad emissions in the summaries that were provided for the NPR) were too high.

Response: EPA reviewed the approach used for commercial marine C_3 emissions in the proposal. In the final modeling, instead of using the boundary of 200 nautical miles from the coast as was used in the proposal, EPA adopted the Mineral Management Service state-federal water boundaries that assign state waters 3–10 nautical miles from the coast. This approach is consistent with the approach used in the 2005 and 2008 National Emission Inventories. In addition, the category 3 commercial marine emissions were adjusted to reflect a coordination between the Emissions Control Area proposal to the International Maritime Organization

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(EPA–420–F–10–041, August 2010) control strategy; reductions of NO_X, VOC, and CO emissions for new C_3 engines starting in 2011; and fuel sulfur limits that go into effect as early as 2010.

f. Development of Emission Inventories for Other Nonroad Mobile Sources

The nonroad mobile source emissions for sources other than C_3 marine were primarily based on NMIM monthly, county, and process level emissions from the 2005 NEI v2. These emissions were unchanged from proposal modeling, except for PM emissions in California that were updated to correct for missing emissions in a few counties and source categories.

Nonroad mobile emissions were created for future years with NMIM using an approach consistent with that used for 2005. The nonroad emissions for 2012 and 2014 were calculated using NMIM future-year equipment population estimates and control programs. Nonroad mobile emission reductions for 2012 and 2014 include reductions to locomotives, various nonroad engines including diesel engines and various marine engine types, fuel sulfur content, and evaporative emissions standards. A more comprehensive list of control programs included for mobile sources is available in the Emission Inventory Final Rule TSD.

The 2012 and 2014 nonroad mobile emissions for locomotives and category 1 and 2 (C1 and C2) commercial marine vessels were based on emissions published in EPA's Locomotive Marine Rule, Regulatory Impact Assessment, Chapter 3.

g. Development of Nonpoint Emission Inventories

For the proposal Transport Rule modeling, EPA augmented the 2002 NEI nonpoint emission inventory with a non-California Western Regional Air Partnership (WRAP) oil and gas exploration inventory, which includes emissions in several states within the eastern U.S. 12 km modeling domain and additional states within the national 36 km modeling domain. For the final Transport Rule modeling, EPA updated the nonpoint emission estimates for oil and gas sources. EPA continued to use the same WRAP inventory from the proposal, emissions in Texas and Oklahoma were updated but for the final modeling with data from the Texas Commission on Environmental Quality (TCEQ) and the Oklahoma Department of Environmental Quality (DEQ), respectively.

The average-year county-based inventories for wildfire and prescribed burning emissions were unchanged between the proposal and final modeling.

For stationary nonpoint sources, local control programs that may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are not included in the future base case projections unless specific information about existing enforceable controls was available (*e.g.,* ozone SIP controls from Ozone Transport Commission rules that impact source categories such as Consumer Products, Solvent Cleaning, Adhesives and Sealants). EPA specifically requested comment on local control data as part of the proposal and the October 27 NODA, and incorporated any usable data that was provided into the final inventories.

For stationary nonpoint sources, refueling emissions were projected using the refueling results from the NMIM runs performed for the onroad mobile sector.

Portable fuel container emissions were projected to future years using estimates from previous OTAQ rulemaking inventories. Emissions of ammonia and dust from animal operations were projected based on animal population data from the Department of Agriculture and EPA. Residential wood combustion was projected by replacement of obsolete wood stoves with new wood stoves and a 1 percent annual increase in fireplaces. Landfill emissions were projected using MACT controls. All other nonpoint sources were held constant between 2005 and the future years.

Some specific adjustments to the inventories were made in the final modeling to address comments that were received as described below. Area source MACT programs and controls from the RICE NESHAP were included in the final modeling to address submitted comments, as were fuel sulfur controls that were enforceable and that take effect by 2014.

The major comments that impacted the nonpoint sectors are as follows:

Comment: Commenters stated that the SO_2 emissions from industrial fuel combustion in Nebraska EPA are too high.

Response: EPA reviewed the NEI 2002-based data that had been used for the proposal modeling and determined that emissions from the 2005 inventory compiled for the Central Regional Air Planning Association (CENRAP) were more up to date for this source category and based on more localized data sources. The 2005 CENRAP emissions for industrial fuel combustion were used in the final modeling.

Comment: Commenters stated that EPA should include sulfur rule controls that take effect prior to the future years that were modeled.

Response: EPA included quantifiable sulfur rule controls in 2014 modeling for those states that had implemented the rules (New Jersey and Maine).

Comment: A commenter stated that emissions for Delaware were overestimated for several nonpoint categories in base-year and future-year inventories and provided alternative estimates for these categories.

Response: EPA reviewed the alternative estimates provided and found them to be credible and based on more detailed local scale information than were available in the national inventories. EPA incorporated the alternative emission estimates for Delaware into the final modeling.

Comment: A commenter stated that residual oil is not used as an industrial fuel in South Carolina.

Response: EPA analyzed the emissions from residual oil industrial fuel combustion in South Carolina and all other states, and analyzed preliminary regional planning office inventories and the 2008 NEI submittals. The South Carolina residual oil industrial fuel emissions were determined to be anomalously large in comparison to the near zero emissions in other submittals and were therefore removed from the nonpoint inventory.

2. Air Quality Basis for Identifying Receptors

a. Introduction

In this section, we describe the final approach to identify downwind nonattainment and maintenance receptors. We briefly summarize the modeling platform, the proposed approach to identify receptors, comments received, and the results of the final analysis.

In the Transport Rule, EPA has explicitly given independent meaning to the ''interfere with maintenance'' prong of section 110(a)(2)(D)(i)(I) by evaluating contributions to identified maintenance receptors as well as contributions to identified nonattainment receptors. EPA identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that takes into account historic variability in air quality at that receptor. Specifically, EPA projects future air quality design values based on measured data during the period 2003 to 2007. In determining the downwind receptors of concern, EPA

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does not solely rely on the projection of an average design value based on measured data from the relevant period (in this case 2003 to 2007) to make a determination of ''attainment'' or ''nonattainment.'' Instead, EPA also evaluates the maximum future design value at that receptor based on measured data over the relevant period. Receptors for which this latter analysis projects design values higher than the NAAQS are identified as maintenance receptors.

EPA believes it is appropriate and reasonable to use this approach to identify receptors that may have maintenance problems in the future. This approach uses measured data in order to establish potential air quality outcomes at each receptor that take into account the variable meteorological conditions present across the entire period of measured data (2003 to 2007). EPA interprets the maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor. In other words, the average design value gives a reasonable projection of future air quality at the receptor under ''average'' conditions. However, EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, air mass patterns) promoting ozone or fine particle formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur. It also identifies upwind emissions that under those circumstances could interfere with the downwind area's ability to maintain the NAAQS.

Per the court's opinion in *North Carolina,* it is necessary for the Agency to evaluate ''interference with maintenance'' separately from ''significant contribution to nonattainment'' in order to give independent meaning to that phrase in the statute. The approach described above does so and provides a reasonable basis for identifying upwind emissions that interfere with maintenance of the NAAQS at downwind receptors.

Because the methodology is based on actual variations in design values measured at the receptors, EPA believes that the application of this design value methodology for identifying maintenance receptors reasonably anticipates possible future air quality outcomes based on meteorological conditions independent of emission reduction requirements occurring between 2005 (the base year for air quality analysis) and 2012 (the future year for air quality analysis of the base case without CAIR or the Transport Rule in place). EPA uses air quality modeling to properly account for changes in air quality from 2005 to 2012 due to emission control requirements and trends in emission source fleet turnover (such as increasingly cleaner motor vehicle fleets). The air quality modeling process allows EPA to effectively adjust measured data to project design values in 2012 based on the forecast changes in emissions. For a given receptor, the forecast change in emissions from 2005 to 2012 is a constant factor applied across all of the design values from the period 2003 to 2007. Thus, a comparison of the projected (future-year) design values themselves is equivalent to comparing the base period design values from the data set to consider how pollution concentrations are affected by non-modeled factors such as environmental and meteorological variability independent of the forecast emission reductions that stem from successful imposition of emission limitations and controls on various sources between the base and future modeling years. EPA believes it is reasonable to anticipate that these year-to-year meteorological fluctuations may reoccur at any time in the future and are relevant to determining receptors that are at risk of having a problem in the future with maintenance of the NAAQS. Therefore, EPA assesses the relationship of the maximum projected design value for 2012 at each receptor to the relevant NAAQS, and where such a value exceeds the NAAQS, EPA determines that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance under the Transport Rule.

To provide an illustrative example, consider a hypothetical receptor ''Y'' whose measured data for 2003–2007 yields three design values for annual fine particles: 17 for 2003–05; 14 for 2004–06; and 12 μg/m³ for 2005–07. Thus, the maximum measured design value for this period is 17 and the average design value is 14.3. To determine whether the receptor is a nonattainment or maintenance receptor, EPA projects a corresponding future-year (2012) design value for each measured design value. These projections are based on the results of air quality modeling, which demonstrates predicted changes in pollution concentrations for each receptor from 2005 to 2012. For this example, assume that the projected future-year design values that correspond with the measured design values, are 16 (corresponds with the 2003–05 design value of 17), 13 (corresponds with the 2004–06 design value of 14), and 11 μg/m³ (corresponds with the 2005–07 design value of 12). The average future-year design value is 13.3 (corresponds with the average measured design value from 2003–2007 of 14.3). The projected future design values are all lower than the measured design values because air quality is projected to improve between 2005 and 2012. In this example, the analysis establishes that the average projected future design value is 13.3 and the maximum projected future design value is 16.

The average future (2012) projected design value of 13.3 based on the average design value for the period 2003–07 does not exceed the 1997 annual $PM_{2.5}$ NAAQS. For this reason, EPA would conclude that receptor Y will most likely have attainment air quality in the future year. Therefore, it would not be identified as a nonattainment receptor.

However, the future projected design value of 16 based on the maximum design value for the period 2003–07 does exceed the NAAQS. For this reason, EPA would conclude that the receptor may have difficulty maintaining attainment with the NAAQS under future potential meteorological conditions. EPA therefore would identify the receptor as a maintenance receptor and evaluate whether upwind state emissions interfere with maintenance of the NAAQS at that receptor.

EPA's methodology accounts for the range of meteorological conditions reflected by design values from the measured 2003–2007 data at receptor Y and also accounts for the projected changes in emissions from 2005 to 2012 at receptor Y. The range of meteorological conditions is accounted for by using data from three different 3-year periods as described above. The projected changes in emissions are accounted for by applying to the measured design values the forecasted change in $PM_{2.5}$ concentrations, as determined through air quality modeling of the 2005 and 2012 emissions. In this example, the maximum measured design value for receptor Y is 17. This design value represents measured data from 2003 to 2005. EPA applies to this design value the modeled 2005–to–2012 change in concentrations at receptor Y to obtain a 2012 maximum design value for that

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receptor, which is 16. In this way, this maximum 2012 design value takes into consideration the air quality impacts of all known and legally applicable emission limitations taking effect after the 2003 to 2005 base period. Therefore, each of the projected future-year design values provide a fair representation of future air quality at receptor Y under different conditions while accounting for the emissions projected to remain in 2012. EPA thus believes that if one of these future-year design values for a particular receptor exceeds the NAAQS, it is reasonable to conclude that the area may have difficulty maintaining that NAAQS. For this reason, EPA identifies such receptors as maintenance receptors. In this example, EPA would find that while receptor Y's average future-year design value would not exceed the NAAQS, its maximum future-year design value (16) would exceed the NAAQS, and it would thus be designated as a ''maintenance'' receptor for purposes of the Transport Rule analyses.

In the proposed rule we used air quality modeling to (1) Identify locations where we expected there to be nonattainment and/or maintenance problems for annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and/or 8-hour ozone in 2012, (2) quantify the impacts (*i.e.,* air quality contributions) of SO_2 and NO_X emissions from upwind states on downwind annual average and 24-hour $PM_{2.5}$ concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 annual and 2006 24-hour $PM_{2.5}$ NAAQS, respectively, and (3) quantify the impacts of NO_X emissions from upwind states on downwind 8-hour ozone concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 ozone NAAQS.

To support the proposal, air quality modeling was performed for four emission scenarios: a 2005 base year, a 2012 ''no CAIR'' base case, a 2014 ''no CAIR'' base case, and a 2014 control case that reflects the emission reductions expected from the FIPs. The modeling for 2005 was used as the base year for projecting air quality for each of the 3 future-year scenarios. The 2012 base case modeling was used to identify future nonattainment and maintenance locations and to quantify the contributions of emissions in upwind states to annual average and 24-hour $PM_{2.5}$ and 8-hour ozone. The 2012 ozone and $PM_{2.5}$ concentrations were derived by projecting 2003 through 2007 based ambient ozone and/or $PM_{2.5}$ data to the future using the relative (percent) change in modeled concentrations between 2005 and 2012. The 2014 base case and 2014 control case modeling were used to quantify the benefits of this proposal.

In the proposed rule, EPA used the Comprehensive Air Quality Model with Extensions (CAMx) version 5.20 [18] to simulate ozone and $PM_{2.5}$ concentrations for the 2005 base year and the 2012 and 2014 future year scenarios. The CAMx model applications were designed to cover states in the central and eastern U.S. using a horizontal resolution of 12 x 12 km.[19]

CAMx contains ''source apportionment'' tools that are designed to quantify the contribution of emissions from various sources and areas to ozone and $PM_{2.5}$ component species in other downwind locations. The source apportionment tools were used to quantify the downwind contributions of ozone and $PM_{2.5}$ from upwind states.

In the proposed rule, EPA used a 2005-based air quality modeling platform which included 2005 base year emissions and 2005 meteorology for modeling ozone and $PM_{2.5}$ with CAMx.

We received comments related to several aspects of the air quality modeling platform.

Comment: There was wide support from commenters for the use of CAMx as an appropriate, state-of-the science air quality tool for use in the Transport Rule. There were no comments that suggested that EPA should use an alternative model for quantifying interstate transport. Many commenters requested that EPA update the emission inventories used for the Transport Rule and then remodel the 2005 base year and future year emissions using the updated emissions and the most recent version of CAMx to reassess interstate transport for the final rule.

Response: For the final rule we have updated our modeling using the latest public release of CAMx (version 5.30) and associated preprocessors. We have also made numerous improvements to the emission inventories for the 2005 base year as well as the 2012 and 2014 future year base cases in response to public comments. The emissions changes are described in section V.C.1. The projection of future year nonattainment and maintenance sites and the quantification of ozone and $PM_{2.5}$ transport for the final rule are based on modeling with CAMx v5.30 using the updated emission inventories. The final rule air quality projections of 2012 nonattainment and maintenance are described below. The final rule interstate contributions are presented in section V.D.

Comment: The performance evaluation of the 2005 base year model predictions for the proposed rule was too cursory and did not provide sufficient detail on model performance. Commenters requested additional analyses and spatial resolution describing how well base year model predictions compare to the corresponding measured values.

Response: For the final rule we have expanded the scope of the model evaluation for 2005 to include a broader suite of statistics to characterize performance for individual subregions of the eastern U.S. modeling domain. The results of the performance evaluation for the final rule 2005 base year air quality modeling are described in the Air Quality Modeling Final Rule TSD.

Comment: The 2005 based modeling platform should be updated to a more recent year. There were several different aspects of this comment. Some commenters stated that EPA should be using a more recent emission inventory as a base year, due to identified changes and updates to the inventories. Other commenters stated that EPA should use a more recent base year, due to a trend of improvement in air quality over the past few years. The commenters claim that the 2005-based EPA modeling does not account for large emission reductions and air quality improvements that have occurred over the last several years.

Response: There are several reasons why the use of a 2005 modeling base case is both reasonable and, in fact, necessary for the Transport Rule. As explained in section V.B, above, because the Transport Rule will replace CAIR, EPA cannot consider reductions associated with CAIR in the analytical baseline emissions scenario. Thus, the base year for the air quality projections should be a year that represents emissions before CAIR was in place (*i.e.* 2005). We are projecting emissions to a future 2012 ''no CAIR'' case and therefore want to best represent the air quality change between 2005 and 2012, without CAIR. To do this, we projected emissions that existed before CAIR was in effect and modeled the air quality change that occurs between 2005 and 2012 without CAIR.

[18] Comprehensive Air Quality Model with Extensions Version 5 User's Guide. Environ International Corporation. Novato, CA. March 2009.

[19] The 12 km domain was nested within a coarse grid, 36 x 36 km modeling domain which covers the lower 48 states and adjacent portions of Canada and Mexico. Predictions from this Continental U.S. (CONUS) domain were used to provide initial and boundary concentrations for simulations in the 12 km domain.

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A key consideration in our projection methodology is the use of ambient data to anchor the design value projections to the future. The modeling is used in a relative sense by multiplying the modeled percent change in ozone or $PM_{2.5}$ species concentrations by the base year ambient data. The ozone and $PM_{2.5}$ modeling guidance recommends projecting design values based on 5 years [20] of monitoring data that is centered on the base model year. Using 2005 as a base emissions and meteorological year entailed the use of 2003–2007 ambient air quality data (5 years of data centered about 2005). This was a reasonable choice because the majority of the ambient data from this period was not impacted by CAIR emission reductions.

After 2005, early emission reductions of SO_2 and NO_X in response to CAIR began to impact the measured air quality concentrations. Since the modeling projection methodology uses both modeled and observed data, 2005 is the latest base year that we deemed appropriate (before CAIR emission reductions took place) for use in projecting the measured air quality to a 2012 future year. The early years of the 5 year period (2003, 2004, and 2005) were not impacted by CAIR.[21] The last 2 years in the period (2006 and 2007) were slightly impacted by CAIR emission reductions. But the 5 year average is weighted towards the middle year of the period (2005), so the impact of the years after CAIR promulgation should be minimal.

The 2005 base year was also chosen because it was an appropriate meteorological year. In the eastern U.S. there was relatively high ozone during the summer of 2005 and relatively high $PM_{2.5}$ periods during the year. The modeled attainment tests for both ozone and 24-hour $PM_{2.5}$ depend on having a sufficient number of ''high'' modeled days to project to the future. Modeling a year that is not meteorologically conducive to ozone and/or $PM_{2.5}$ formation is discouraged by the modeling guidance because a meteorological year that is not conducive to ozone or $PM_{2.5}$ formation may be less responsive to changes in emissions in the future. Therefore, projecting the relative change in ozone or $PM_{2.5}$ for a non-conducive base year may underestimate the future change in ozone and/or $PM_{2.5}$ concentrations.

[20] The modeling guidance recommends using a five year weighted average design value. This is calculated by averaging the three consecutive design value periods of 2003–2005, 2004–2006, and 2005–2007.

[21] The CAIR final rule was published on May 12, 2005.

Additionally, all enforceable emission reductions that occurred between 2005 and 2012 (other than those required under CAIR) are captured by the modeling system. Any enforceable non-EGU emission reductions due to existing rules or the installation of emissions controls after 2005 were included in the 2012 base case inventory. As explained above in section V.B, to capture changes in EGU emissions between 2005 and 2012, EPA did not assume operation of all controls installed during that time period, as many of those controls were built in response to CAIR. EPA used IPM to project 2012 EGU emissions incorporating all non-CAIR enforceable emission constraints; operation of existing pollution controls was taken into account only where non-CAIR constraints made it economic or legally necessary to operate them. We also accounted for permanent source shutdowns that occurred after 2005. Where possible, we incorporated reported emission changes based on comments to the proposed rule and a subsequent emission inventory NODA.

Comment: Several commenters stated that we used a ''modeled + monitored'' test in CAIR to identify future year nonattainment receptors, but we only used a modeled test in the Transport Rule proposal. They suggest that we should either go back to the ''modeled + monitored'' test or explain why we should not use monitoring data in the identification of nonattainment and maintenance receptors. They say that we should not base nonattainment and maintenance receptors solely on modeled violations. They also say that we if we had looked at the most recent ambient data we would see that most of the modeled nonattainment and maintenance receptors are already attaining the ozone and/or $PM_{2.5}$ NAAQS.

Response: In the identification of future year nonattainment receptors for CAIR, EPA used what was called the ''modeled + monitored test''. The most recent ambient data (2001–2003 design values at the time) were examined to further verify that nonattainment was still being measured at potential future year nonattainment receptors. In the proposed Transport Rule, EPA identified future year nonattainment and maintenance receptors based on modeled projections of ambient data from the 2003–2007 time period. The future year receptors were not compared to most recent ambient data to verify that nonattainment still existed.

For the final Transport Rule, there are several reasons that EPA did not examine the most recent ambient data to verify that receptors were still measuring nonattainment. The main reason for dropping the ''monitored'' part of the modeled + monitored test is the fact that the most recent monitoring data (2007–2009 design values) include large emission reductions from CAIR. As explained in section V.B, above, because the Transport Rule will replace CAIR, we must model a future year base case which does not assume that CAIR is in place (a ''no-CAIR'' case). It is simply not appropriate to examine the current monitoring data, which represent air quality with CAIR emission reductions in place, and compare the values to 2012 projected air quality that is based on a no-CAIR modeling case. As discussed above, we modeled a 2005 base case with pre-CAIR emissions and a 2012 future ''no CAIR'' case. The change in modeled air quality is due to the non-CAIR enforceable emission changes between 2005 and 2012 and therefore explicitly does not take CAIR into account. As a consequence, the 2012 projected design values represent a unique case (necessary for analyzing future air quality without either CAIR or its replacement Transport Rule in effect) that cannot be represented by current ambient data.

It is also important to note that all of the projected 2012 design values are based on projections of measured ambient data. They are a combination of measured data and modeled response factors. Therefore, it is inaccurate to imply that future year nonattainment and maintenance receptors are solely based on modeled projections. The future year concentrations are firmly rooted in base year measured ambient data that have been projected to the future using modeled data.

There are additional reasons for not verifying the nonattainment and maintenance receptors against the most recent ambient data. In CAIR we did not explicitly identify maintenance receptors. In the Transport Rule proposal we identified maintenance receptors based on 2012 projections of maximum design values from the 2003–2007 period. Even though receptors may be measuring attainment based on recent data, they may still be at risk for falling back into nonattainment. Therefore, even if commenters argue that recent data show that monitoring sites should not be nonattainment receptors (with which we disagree), the same argument cannot be made regarding maintenance receptors. Clearly, receptors with recent ''clean'' ambient data may still experience higher $PM_{2.5}$ and/or ozone concentrations in the future (based on

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meteorological and emission variability) and therefore may be appropriate maintenance receptors.

Comment: Several commenters claim that the maintenance receptor methodology overstates actual future design values. They also recommend an alternative methodology which takes into account the downward trend in observed $PM_{2.5}$ concentrations over the last 5+ years. The methodology would remove the trend in the data where air quality is improving over the period by applying a linear fit to the data, calculating the residuals and then adding the residuals back to the average of the data. Given a site with a downward trend, this has the effect of decreasing the calculated maximum values from the early years in the period and increasing the values from the end years in the period.

Response: EPA continues to believe that our approach to identify maintenance receptors is reasonable and appropriate. For the final rule, we continue to identify maintenance receptors by projecting the maximum design value from the 2003–2007 period to the future. The methodology assumes that the combination of emissions and meteorology that occurred in the base period (which led to relatively high ambient design values) could happen again in the future (albeit at lower emissions levels). There is no information presented by the commenters which explains why the magnitude of base year design value variability could not occur in the same way in the future. The commenters cite the downward trend in ambient data as the reason why the EPA methodology is not reasonable. However, in most cases, the recent downward trend in ambient data is due to a combination of ongoing emission reductions (which includes CAIR), variability in meteorology, and depressed emissions due to the recession. In fact, the most recent ambient design value period (2007–2009) is heavily influenced by extremely low ozone and $PM_{2.5}$ concentrations measured in 2009. The 2009 data are marked by relatively low emissions due to cool summer weather and ongoing effects of the recession. The preliminary [22] 2010 ambient data in the eastern U.S. show that ozone and $PM_{2.5}$ values were considerably higher in 2010 compared to 2009. In the states that are included in the final Transport Rule region, there were 158 ozone monitor days that exceeded 84 ppb in 2009 compared to 412 monitor exceedance days in 2010. For $PM_{2.5}$, there were 251 monitor days that exceeded 35 $\mu g/m^3$ in 2009 compared to 417 monitor exceedance days in 2010. Even though the SO_2 and NO_X emissions were generally lower in 2010, the observed ozone and $PM_{2.5}$ concentrations were higher. This shows the important influence of meteorology on ambient concentrations. Clearly, the year to year variability due to meteorology can be large. We acknowledge the downward trend in ambient data over the last few years. But this does not mean that conditions that led to high ozone and/or $PM_{2.5}$ in the 2003–2007 period could not occur again in the future. The 2010 ambient data show that meteorology can cause concentrations to go back up, even though there is a downward trend in emissions.

We also believe that the alternate maintenance methodology presented by the commenter is inappropriate. The EPA modeling for 2012 (and 2014) appropriately accounts for emission reductions that occur after 2005 except for those that should not be considered, as explained in section V.B., because they were required only by CAIR. Therefore, the starting point design values used to project to the future should not be lowered to account for emission reduction trends that occur after 2005. Doing so would give ''double credit'' to the more recent emission reductions and provides an inappropriate downward adjustment to the early design value periods of the 2003–2007 period.

Comment: One commenter claims that EPA did not follow our own modeling guidance by not doing local scale modeling in urban areas with high $PM_{2.5}$ concentration gradients. They suggested that the methodology to calculate future year design values should have included dispersion modeling to calculate the change in concentration over time of primary $PM_{2.5}$ emissions.

Response: EPA modeling guidance for $PM_{2.5}$ attainment demonstrations recommends photochemical grid modeling to examine future year changes in $PM_{2.5}$ concentrations. There are several optional aspects of the modeling which are recommended in specific cases. This includes a recommendation for a ''local area analysis'' using a dispersion model. An area with relatively large local primary $PM_{2.5}$ concentration gradients may want to do additional modeling to examine the impacts of local controls on its future year $PM_{2.5}$ concentrations. This is particularly important when local controls of primary $PM_{2.5}$ are included as part of the attainment demonstration.

As noted above, a ''local area analysis'' is recommended as part of the local attainment demonstration process in specific situations. It is impractical for EPA to perform this type of analysis for each local area in the regional Transport Rule. National rulemakings are not attainment demonstrations. We are not able to perform fine scale analyses for each area. For the final rule modeling, we have attempted to address all emissions and modeling related comments. We have updated the modeling platform to use the latest version of CAMx and are continuing to model ozone and $PM_{2.5}$ at 12km grid resolution, which for $PM_{2.5}$ is a more refined grid resolution compared to the CAIR modeling.

Additionally, there is no evidence presented by the commenter that would indicate that the future year $PM_{2.5}$ concentrations from the Transport Rule are biased high. In fact, depending on the circumstances, local fine scale grid or dispersion modeling may result in lower or higher future year design values. In a fine scale analysis, the dominant local primary $PM_{2.5}$ emissions become a larger percentage of the $PM_{2.5}$ concentrations. Therefore, if the local emissions are forecast to decrease, fine scale modeling may lead to lower future design values. However, if the local emissions are forecast to increase or stay the same between the base and future years, local modeling will likely show higher future year design values compared to a regional analysis. This points to the fact that perceived biases in modeling results may not always be correct.

In sum, fine scale modeling of local areas may lead to either higher or lower future year design values. There is no indication that EPA's regional modeling is biased in either direction. EPA's Transport Rule modeling generally followed EPA's modeling guidance and is appropriate for the purpose of this rulemaking.

Comment: One commenter completed and submitted a detailed CAMx based modeling analysis with a 2008 base year and future years of 2014 and 2018. The analysis shows that the majority of the proposed rule 2012 nonattainment and maintenance sites are already attaining based on either 2006–2008 or 2007–2009 ambient data. Based on this, the commenter claims that air quality has improved more rapidly than predicted by EPA's proposed rule modeling. Also, based on the commenter's 2014 modeling of CAIR emissions (including utility consent decrees and state programs), the commenter concludes that no additional controls are needed

[22] The 2010 data is preliminary. Exceptional event data has not been flagged and removed from the reported data.

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beyond CAIR to bring most or all sites into attainment by 2014.

Response: As an initial matter, we note that the basic question addressed by the commenter, ''whether additional controls beyond CAIR are necessary,'' is not on point. As explained previously, the D.C. Circuit remanded CAIR to EPA and it remains in place only temporarily. The question EPA must answer in this rulemaking, therefore, is not what controls in addition to CAIR are necessary but what, if any, restrictions on emissions must be put in place to replace CAIR in order to satisfy the requirements of section 110(a)(2)(D)(i)(I) of the CAA. For this reason, and as explained in greater detail in section V.B of this preamble, any analysis of whether beyond CAIR controls are necessary is irrelevant to this rulemaking. Nonetheless, we have carefully reviewed different aspects of the commenter's analysis. We previously addressed comments related to the use of more recent ambient data to examine future year nonattainment and maintenance receptors. As noted above, the 2006–2008 and 2007–2009 ambient data is heavily influenced by several factors. Among them are the emissions reductions from CAIR, the relatively low recent observed ozone and $PM_{2.5}$ concentrations at least partially due to non-conducive meteorology (particularly in 2009), and the atypical suppression of emissions due to the sharp recession. For all of these reasons, we believe it is not possible to directly compare the most recent design values to the predicted future year 2012 and 2014 design values from the Transport Rule. In particular, it is inappropriate to compare current design values to EPA's no-CAIR 2012 future year modeling results. As noted in the comment summary, the commenter's modeling analysis assumed that CAIR was in place in both 2008 and the future years. This is a fundamentally different assumption than the modeling EPA used to define the Transport Rule nonattainment and maintenance receptors in 2012 and is inappropriate for purposes of the Transport Rule for reasons described above and in section V.B.

Additionally, EPA's maintenance methodology chooses the highest of three base year design value periods projected to the future. The commenter only used a single design value period in their analysis and therefore did not fully examine maintenance issues. In fact, the 2014 nonattainment modeling receptors in the final Transport Rule and the commenter's modeling analysis are similar. As documented in section VI.D, in the 2014 final rule remedy case, there is only one remaining nonattainment area for ozone and one remaining nonattainment area for 24-hour $PM_{2.5}$. This is similar to the modeling results presented in the comments.[23] However, EPA modeling identifies additional maintenance receptors in 2012 that continue to have maintenance issues in 2014.

EPA also examined our ozone and $PM_{2.5}$ projection procedures to see if there might be additional reasons for the relatively lower current ambient design values (and modeled design values in the commenter's analysis) compared to the 2014 remedy modeled values. Upon further analysis of EPA's 24-hour attainment test methodology, we noted certain discrepancies between the methodology and the calculation of the ambient 24-hour design values. In the proposed rule 24-hour attainment test, for each $PM_{2.5}$ monitor, we projected the measured 98th percentile concentrations from the 2003–2007 period to the future. A basic assumption in this methodology is that the distribution of high measured days in the base period will be the same in the future. For example, if the observed 98th percentile day is the 3rd high day for a particular year, we assume that the 1st, 2nd, and 3rd high days (and subsequent high days) in the future remain in the same basic distribution. Further examination of the proposed rule modeling found that this is not always the case. In situations where there are large summer $PM_{2.5}$ concentration reductions, some of the high days may switch from the summer in the base period to the winter in the future period.

In order to better account for the complicated future response in 24-hour design values, we have updated the 24-hour attainment demonstration methodology to more closely reflect the way 24-hour design values are calculated. In the revised methodology, we do not assume that the temporal distribution of high days in the base and future periods will remain the same. We project a larger set of ambient days from the base period to the future and then re-rank the entire set of days to find the new future 98th percentile value (for each year). More specifically, we project the highest 8 days per quarter (32 days per year) to the future and then re-rank the 32 days to derive the future year 98th percentile concentrations. In the case of the Transport Rule model results, this has the effect of lowering the future year 24-hour design values compared to the old methodology. The 2012 base case design values for all nonattainment and maintenance receptors were either unchanged or lower with the revised methodology.

3. How did EPA project future nonattainment and maintenance for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone?

Final Rule: In general, the methodology to project ozone and $PM_{2.5}$ concentrations to the future year(s) remains the same for the final rule. The proposal modeling followed the modeling guidance procedures for projecting ambient design values to future years. For the final rule, we continue to follow the basic procedures outlined in the guidance. The 8-hour ozone and annual $PM_{2.5}$ methodology are unchanged from the proposal. However, the 24-hour $PM_{2.5}$ methodology has been updated in the final rule to be more consistent with the calculation of 24-hour $PM_{2.5}$ design values. There were also additional minor updates to the ambient data.[24] The methodology to identify maintenance receptors is also unchanged from the proposal. We continue to use the maximum design value (projected from the 5 year base period) to calculate future year maintenance receptors.

As noted in the proposal, EPA considers that the maintenance concept has two components: Year-to-year variability in emissions and air quality, and continued maintenance of the air quality standard over time. The way that EPA defined maintenance based on year-to-year variability (as discussed in detail here) directly affects the requirements of this final rule. EPA also considered whether further reductions were necessary to ensure continued lack of interference with maintenance of the NAAQS over time (*e.g.,* after 2014). EPA concluded that in light of projected emission trends, and also considering the emission reductions from this proposed rule, no further reductions are required solely for this purpose at $PM_{2.5}$ and ozone receptors for which we are partially or fully determining significant contribution for the current NAAQS. (*See* discussion of emission trends in Chapter 7 of TSD entitled ''Emission Inventories,'' included in the docket for the Transport Rule proposal.)

[23] The purpose of this comparison is to note that the modeling analyses are actually more similar than the commenter implies. However, the Transport Rule differs from the commenter's modeling due to the assumption that CAIR was in place. CAIR and the Transport Rule differ in state coverage and emission budgets. They are therefore not directly comparable.

[24] The base year design values were updated based on the latest official data. *See http://www.epa.gov/airtrends/values.html.*

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a. Which ambient ozone and $PM_{2.5}$ data did EPA use for the purpose of projecting future year concentrations?

The final rule modeling continues to use a 2005 base case inventory and 2005 meteorology. Therefore, we continue to use ambient data from the 2003–2007 period. For each monitoring site, all valid design values (up to 3) from this period were averaged together. Since 2005 is included in all three design value periods, this has the effect of creating a 5-year weighted average, where the middle year is weighted 3 times, the 2nd and 4th years are weighted twice, and the 1st and 5th years are weighted once. We refer to this as the 5-year weighted average value. The 5-year weighted average values were then projected to the future years that were analyzed for this final rule. The 2003–2005, 2004–2006, and 2005–2007 design values are accessible at *http://www.epa.gov/airtrends/values.html.* The design values have been updated based on the latest official values. The official values have exceptional events removed from the calculations if they are flagged by states and concurred with by EPA Regional offices.

The procedures for projecting annual average $PM_{2.5}$ and 8-hour ozone conform to the methodology in the current attainment demonstration modeling guidance.[25]

b. Projection of Future Annual and 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

(1) Methodology for Projecting Future Annual $PM_{2.5}$ Nonattainment and Maintenance

For the final rule, annual $PM_{2.5}$ modeling was performed for the 2005 base year emissions and for the 2012 base case as part of the approach for projecting which locations are expected to be in nonattainment and/or have difficulty maintaining the $PM_{2.5}$ standards in 2012. We refer to these areas as nonattainment sites and maintenance sites respectively.

Concentrations of $PM_{2.5}$ in 2012 were estimated by applying the modeled 2005-to-2012 relative change in $PM_{2.5}$ species to each of the 3-year ambient monitoring data periods (*i.e.,* 2003–2005, 2004–2006, and 2005–2007) to obtain up to 3 future-year $PM_{2.5}$ design values for each monitoring site. We used the highest of these projections at each monitoring site to determine which sites are expected to have maintenance problems in 2012. We used the 5 year weighted average of those projections to determine which monitoring sites are expected to be nonattainment in this future year.

For the analysis of both nonattainment and maintenance, monitoring sites were included in the analysis if they had at least one complete design value in the 2003–2007 period.[26] There were 721 monitoring sites in the 12 km modeling domain which had at least one complete design value period for the annual $PM_{2.5}$ NAAQS, and 722 sites which met this criterion for the 24-hour NAAQS.[27]

EPA followed the procedures recommended in the modeling guidance for projecting $PM_{2.5}$ by projecting individual $PM_{2.5}$ component species and then summing these to calculate the concentration of total $PM_{2.5}$. EPA's Modeled Attainment Test Software (MATS) was used to calculate the future year design values. The software (including documentation) is available at: *http://www.epa.gov/scram001/modelingapps_mats.htm.* Additional details on the annual $PM_{2.5}$ nonattainment and maintenance projections methodology can be found in the Air Quality Modeling Final Rule TSD.

The 2012 annual $PM_{2.5}$ design values were calculated for each of the 721 sites. The calculated annual $PM_{2.5}$ design values are truncated after the second decimal place.[28] This is consistent with the ambient monitoring data truncation and rounding procedures for the annual $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 15.05 $\mu g/m^3$ is rounded to 15.1 $\mu g/m^3$ and is considered to be violating the NAAQS. Thus, sites with projected 5-year weighted average (''average'') annual $PM_{2.5}$ design values of 15.05 $\mu g/m^3$ or greater are predicted to be nonattainment sites. Sites with projected maximum design values of 15.05 $\mu g/m^3$ or greater are predicted to be maintenance sites. Note that nonattainment sites are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term ''nonattainment sites'' to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value, but exceed the NAAQS based on the maximum design value, are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the annual $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the annual $PM_{2.5}$ NAAQS.

Table V.C–1 contains the 2003–2007 base case period average and maximum annual $PM_{2.5}$ design values and the corresponding 2012 base case average and maximum design values for sites projected to be nonattainment of the annual $PM_{2.5}$ NAAQS in 2012. Table V.C–2 contains this same information for projected 2012 maintenance sites.

TABLE V.C–1—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES ($\mu G/M^3$) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
010730023	Alabama	Jefferson	18.57	18.94	16.15	16.46
010732003	Alabama	Jefferson	17.15	17.69	15.16	15.64
131210039	Georgia	Fulton	17.43	17.47	15.07	15.10
171191007	Illinois	Madison	16.72	17.01	15.46	15.73
261630033	Michigan	Wayne	17.50	18.16	15.73	16.32

[25] U.S. EPA, 2007: Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze; Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[26] If there is only one complete design value, then the nonattainment and maintenance design values are the same.

[27] Design values were only used if they were deemed to be officially complete based on CFR 40 Part 50 Appendix N. The completeness criteria for the annual and 24-hour $PM_{2.5}$ NAAQS are different. Therefore, there are fewer complete sites for the annual NAAQS.

[28] For example, a calculated annual average concentration of 14.94753 * * * becomes 14.94 when digits beyond two places to the right of the decimal are truncated.

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TABLE V.C–1—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES (μG/M³) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
390350038	Ohio	Cuyahoga	17.37	18.10	15.99	16.66
390350045	Ohio	Cuyahoga	16.47	16.98	15.14	15.61
390350060	Ohio	Cuyahoga	17.11	17.66	15.67	16.18
390610014	Ohio	Hamilton	17.29	17.53	15.76	15.98
390610042	Ohio	Hamilton	16.85	17.25	15.40	15.77
390618001	Ohio	Hamilton	17.54	17.90	16.01	16.33
420030064	Pennsylvania	Allegheny	20.31	20.75	17.94	18.33

TABLE V.C–2—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES (μG/M³) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
180970081	Indiana	Marion	16.05	16.36	14.86	15.16
180970083	Indiana	Marion	15.90	16.27	14.71	15.06
390350065	Ohio	Cuyahoga	15.97	16.44	14.67	15.10
390617001	Ohio	Hamilton	16.17	16.56	14.74	15.10

(2) Methodology for Projecting Future 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

The procedures for calculating the future year 24-hour $PM_{2.5}$ design values have been updated for the final rule.[29] The revised procedures are in response to comments which noted relatively high future year 24-hour $PM_{2.5}$ design values in EPA's modeling of the proposed Transport Rule. The updates are intended to make the projection methodology more consistent with the procedures for calculating ambient design values.

As noted above, for the proposed Transport Rule EPA projected for each $PM_{2.5}$ monitor the measured 98th percentile concentrations from the 2003–2007 period to the future. As an additional check, we also projected the next highest concentrations from the three calendar quarters in each year when the 98th percentile did not occur in the 2003–2007 base period, to ensure that the future year 98th percentile did not switch seasons in the future year compared to the base year. A basic assumption in this methodology is that the distribution of high measured days in the base period will be the same in the future.

In other words, EPA assumed at proposal that the 98th-percentile day could only be displaced ''from below'' in the instance that a different day's future concentration exceeded the original 98th-percentile day's future concentration. In that case, the original 98th-percentile day may become the 97th- or 96th-percentile day in the future year; EPA accounted for this possibility at proposal. EPA did not, however, consider that the 98th-percentile day could also be displaced ''from above'' in the instance that higher-concentration days in the base period were projected to have future concentrations lower than the original 98th-percentile day's future concentration. In that case, the original 98th-percentile day may become the 99th- or 100th-percentile day. Because EPA continued to use that day's future concentration to determine the monitor's future design value at proposal, this sometimes resulted in overstatement of future-year design values for 24-hour $PM_{2.5}$ monitoring sites whose seasonal distribution of highest-concentration 24-hour $PM_{2.5}$ days changed between the 2003–2007 period and the future year modeling. Examination of the proposed rule remedy modeling (2014 remedy case) showed that many of the highest $PM_{2.5}$ days switched from the summer in the base period to the winter in the future period. This is especially true in areas of the upper Midwest which experience both high summer and winter $PM_{2.5}$ episodes.

In the revised methodology, we do not assume that the seasonal distribution of high days in the base period years and future years will remain the same. We project a larger set of ambient days from the base period to the future and then re-rank the entire set of days to find the new future 98th percentile value (for each year). More specifically, we project the highest 8 days per quarter (32 days per year) to the future and then re-rank the 32 days to derive the future year 98th percentile concentrations. In the case of the Transport Rule model results, this has the effect of lowering the future year 24-hour design values compared to the old methodology.

The modeling guidance recommendations for state attainment demonstrations have been updated to reflect the changes outlined above. Further details on the 24-hour $PM_{2.5}$ design value calculations can be found in the Air Quality Modeling Final Rule TSD. The above procedures for determining future year 24-hour $PM_{2.5}$ concentrations were applied for each site. The 24-hour $PM_{2.5}$ design values are truncated after the first decimal place. This approach is consistent with the ambient data truncation and rounding procedures for the 24-hour $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 35.5 μg/m³ is rounded to 36 μg/m³ and is violating the NAAQS. Sites with future year 5-year weighted average design values of 35.5 μg/m³ or greater, based on the projection of 5-year weighted average concentrations, are predicted to be nonattainment. Sites with future year maximum design values of 35.5 μg/m³ or greater are predicted to be maintenance sites. Note that nonattainment sites for the 24-hour NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. The monitoring

[29] There were no updates to the ozone and annual $PM_{2.5}$ attainment test methodology.

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sites that we project to be nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of 24-hour $PM_{2.5}$ NAAQS as part of this final rule.

Table V.C–3 contains the 2003–2007 base period average and maximum 24-hour $PM_{2.5}$ design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 24-hour $PM_{2.5}$ NAAQS in 2012. Table V.C–4 contains this same information for projected 2012 24-hour maintenance sites.

TABLE V.C–3—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (μG/M3) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
010730023	Alabama	Jefferson	44.0	44.2	36.9	37.3
170311016	Illinois	Cook	43.0	46.3	37.5	40.4
171191007	Illinois	Madison	39.1	40.1	36.5	36.8
180970043	Indiana	Marion	38.4	39.9	35.7	37.1
180970066	Indiana	Marion	38.3	39.6	35.7	36.9
180970081	Indiana	Marion	38.2	39.2	35.8	36.9
261470005	Michigan	St Clair	39.6	40.6	36.2	37.1
261630015	Michigan	Wayne	40.1	40.6	35.5	36.0
261630016	Michigan	Wayne	42.9	45.4	38.9	41.2
261630019	Michigan	Wayne	40.9	41.4	37.3	37.8
261630033	Michigan	Wayne	43.8	44.2	39.4	39.8
390350038	Ohio	Cuyahoga	44.2	47.0	39.4	41.8
390350060	Ohio	Cuyahoga	42.1	45.7	37.7	40.8
420030064	Pennsylvania	Allegheny	64.2	68.2	56.7	59.9
420030093	Pennsylvania	Allegheny	45.6	51.5	39.1	44.3
420030116	Pennsylvania	Allegheny	42.5	42.5	35.5	35.5
420070014	Pennsylvania	Beaver	43.4	44.6	36.2	37.4
420710007	Pennsylvania	Lancaster	40.8	44.0	35.9	38.3
540090011	West Virginia	Brooke	43.9	44.9	37.5	38.3
550790043	Wisconsin	Milwaukee	39.9	40.8	36.2	37.1

TABLE V.C–4—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (μG/M^3) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
010732003	Alabama	Jefferson	40.3	40.8	35.3	35.9
170310052	Illinois	Cook	40.2	41.4	34.9	36.0
170312001	Illinois	Cook	37.7	40.6	33.6	36.1
170313301	Illinois	Cook	40.2	43.3	34.9	37.6
170316005	Illinois	Cook	39.1	41.8	34.1	36.4
171190023	Illinois	Madison	37.3	38.1	35.1	35.8
180890022	Indiana	Lake	38.9	44.0	34.9	39.5
180890026	Indiana	Lake	38.4	41.3	34.0	37.0
261610008	Michigan	Washtenaw	39.4	40.8	35.0	36.3
390170003	Ohio	Butler	39.2	41.1	34.4	36.5
390350045	Ohio	Cuyahoga	38.5	41.5	34.7	38.1
390350065	Ohio	Cuyahoga	38.6	41.0	34.9	37.6
390618001	Ohio	Hamilton	40.6	40.9	35.2	35.8
390811001	Ohio	Jefferson	41.9	45.5	34.5	37.8
391130032	Ohio	Montgomery	37.8	40.0	33.6	35.6
420031008	Pennsylvania	Allegheny	41.3	42.8	35.0	36.3
420031301	Pennsylvania	Allegheny	40.3	42.4	33.9	35.6
420033007	Pennsylvania	Allegheny	37.5	43.1	32.3	37.3
421330008	Pennsylvania	York	38.2	40.7	33.3	36.0
550790010	Wisconsin	Milwaukee	38.6	40.0	35.4	36.7
550790026	Wisconsin	Milwaukee	37.3	41.3	33.6	37.2

(3) Methodology for Projecting Future 8-Hour Ozone Nonattainment and Maintenance

The final rule methodology to calculate 8-hour ozone nonattainment and maintenance receptors is identical to the proposed rule. The May-to-September 24-hour maximum 8-hour average concentrations from the 2005 base case and the 2012 base case were used to project ambient design values to 2012. The following is a brief summary of the future year 8-hour average ozone calculations. Additional details are provided in the Air Quality Modeling Final Rule TSD.

We are using the base period 2003–2007 ambient ozone design value data for projecting future year design values. Relative response factors (RRF) for each monitoring site were calculated as the

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percent change in ozone on days with modeled ozone greater than 85 ppb.[30]

The maximum future design value is calculated by projecting design values for each of the three base periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. This maximum value is used to identify the 8-hour ozone maintenance receptors.

The future year design values are truncated to integers in units of ppb. This approach is consistent with the ambient data truncation and rounding procedures for the 8-hour ozone NAAQS. Future year design values that are greater than or equal to 85 ppb are considered to be violating the NAAQS. Sites with future year 5-year weighted average design values of 85 ppb or greater are predicted to be nonattainment. Sites with future year maximum design values of 85 ppb or greater are predicted to be future year maintenance sites. Note that, as described previously for the annual and 24-hour $PM_{2.5}$ NAAQS, nonattainment sites for the ozone NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. The monitoring sites that we project to be nonattainment and/or maintenance for the 8-hour ozone NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of ozone NAAQS.

Table V.C–5 contains the 2003–2007 base period average and maximum 8-hour ozone design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 8-hour ozone NAAQS in 2012. Table V.C–6 contains this same information for projected 2012 8-hour ozone maintenance sites.

TABLE V.C–5—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Final rule average design value 2012	Final rule maximum design value 2012
220330003	Louisiana	East Baton Rouge	92.0	96	85.6	89.3
480391004	Texas	Brazoria	94.7	97	86.7	88.8
482010051	Texas	Harris	93.0	98	86.1	90.8
482010055	Texas	Harris	100.7	103	93.3	95.4
482010062	Texas	Harris	95.7	99	88.8	91.8
482010066	Texas	Harris	92.3	96	87.1	90.6
482011039	Texas	Harris	96.3	100	88.8	92.2

TABLE V.C–6—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
090011123	Connecticut	Fairfield	92.3	94	83.9	85.5
090093002	Connecticut	New Haven	90.3	93	82.7	85.1
240251001	Maryland	Harford	92.7	94	84.4	85.6
260050003	Michigan	Allegan	90.0	93	82.4	85.1
482010024	Texas	Harris	88.0	92	83.4	87.2
482010029	Texas	Harris	91.7	93	84.2	85.4
482011015	Texas	Harris	89.0	96	82.4	88.9
482011035	Texas	Harris	86.3	95	79.9	88.0
482011050	Texas	Harris	89.3	92	82.8	85.4

D. Pollution Transport From Upwind States

1. Choice of Air Quality Thresholds

a. Thresholds

In this action, EPA uses air quality thresholds to identify linkages between upwind states and downwind nonattainment and maintenance receptors. States whose contributions to a specific receptor meet or exceed the thresholds identified are considered linked to that receptor; those states' emissions (and available emission reductions) are analyzed further in the second step of EPA's significant contribution analysis. States whose contributions are below the thresholds are not included in the Transport Rule for that NAAQS. In other words, we are finding that states whose contributions are below these thresholds do not significantly contribute to nonattainment or interfere with maintenance of the relevant NAAQS.

We use separate air quality thresholds for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. Each air quality threshold is calculated as 1 percent of the NAAQS. Specifically, we use an air quality threshold of 0.15 $\mu g/m^3$ for annual $PM_{2.5}$, 0.35 $\mu g/m^3$ for 24-hour $PM_{2.5}$, and 0.8 ppb for 8-hour ozone. These are the same air quality thresholds we proposed.

EPA received a number of comments on the thresholds we proposed, and those comments and EPA's responses are discussed below.

b. General Comments on the Overall Stringency and Use of 1 Percent of the NAAQS

EPA received numerous comments supporting and opposing the proposed thresholds. A number of commenters cited support for EPA's approach. Some

[30] As specified in the attainment demonstration modeling guidance, if there are less than 10 modeled days > 85 ppb, then the threshold is lowered in 1 ppb increments (to as low as 70 ppb) until there are 10 days. If there are less than 5 days > 70 ppb, then an RRF calculation is not completed for that site.

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commenters believed that use of a 1 percent threshold was too stringent, and recommended that EPA should use a threshold greater than 1 percent. Others believed that 1 percent was not stringent enough, and they recommended using a lower value such as 0.5 percent. EPA believes that for both $PM_{2.5}$ and for ozone, it is appropriate to use a threshold of 1 percent of the NAAQS for identifying states whose contributions do not significantly contribute to nonattainment or interfere with maintenance of the relevant NAAQS; therefore, EPA has retained the 1 percent threshold for the reasons described below.

As we found at the time of CAIR, EPA's analysis of base case $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and, in some cases, substantially larger contributions from a subset of particular upwind states. (*See* section II of the January 2004 CAIR proposal, 69 FR 4575–87).

In the 1998 NO_X SIP Call (63 FR 57456, October 27, 1998) and in CAIR, EPA also found important contributions from multiple upwind states. As a result of the upwind ''collective contributions,'' EPA determined that it is appropriate to use a low air quality threshold when analyzing upwind states' contributions to downwind states' attainment and maintenance problems for ozone as well as $PM_{2.5}$.

Low threshold values are also warranted, as EPA discussed in the notices for CAIR, due to adverse health impacts associated with ambient $PM_{2.5}$ and ozone even at low concentrations (See relevant portions of the CAIR proposal notice (63 FR 4583–84) and the CAIR final rule notice (70 FR 25189–25192)).

To aid in responding to comments, EPA has compiled the contribution modeling results to analyze the impact of different possible thresholds. This analysis demonstrates the reasonableness of using the 1 percent threshold to account for the combined impact of relatively small contributions from many upwind states (see Air Quality Modeling Final Rule TSD). In this analysis, EPA identifies for annual $PM_{2.5}$ (sulfate and nitrate), 24-hour $PM_{2.5}$ (sulfate and nitrate), and 8-hour ozone receptors: (1) Total upwind state contributions, and (2) the amount of the total upwind state contribution that is captured at thresholds of 1 percent, 5 percent and 0.5 percent of the NAAQS. EPA continues to find that the total ''collective contribution'' from upwind sources represents a large portion of $PM_{2.5}$ and ozone at downwind locations and that the total amount of transport is composed of the individual contribution from numerous upwind states.

The analysis shows that the 1 percent threshold captures a high percentage of the total pollution transport affecting downwind states for both $PM_{2.5}$ and ozone. In response to commenters who advocated a higher threshold, EPA observes that higher thresholds would exclude increasingly large percentages of total transport, which we do not believe would be appropriate. For example, a 5 percent threshold would exclude the majority—and for annual PM, more than 80 percent—of interstate pollution transport affecting the downwind state receptors analyzed (based on the average percentage of total interstate transport across all receptors captured at the 5 percent threshold).

In response to commenters who advocated a lower threshold, EPA observes that the analysis shows that a lower threshold such as 0.5 percent would result in relatively modest increases in the overall percentages of $PM_{2.5}$ and ozone pollution transport captured relative to the amounts captured at the 1 percent level. A 0.5 percent threshold could lead to emission reduction responsibilities in additional states that individually have a very small impact on those receptors—an indicator that emission controls in those states are likely to have a smaller air quality impact at the downwind receptor. We are not convinced that selecting a threshold below 1 percent is necessary or desirable. A strong indication that the amount of pollution transport being excluded from consideration is not excessive is that the controls required under this rule are projected to eliminate nonattainment and maintenance problems with air quality standards at most downwind state receptors.

Considering the combined downwind impact of multiple upwind states, the health effects of low levels of $PM_{2.5}$ and ozone pollution, and EPA's previous use of a 1 percent threshold for $PM_{2.5}$ in CAIR, EPA's judgment is that the 1 percent threshold is a reasonable choice.

Some commenters noted that the $PM_{2.5}$ thresholds used for this rule are less than the ''significant impact levels'' (SILs) used for permitting programs. As EPA stated at the time of CAIR, since the thresholds referred to by the commenters serve different purposes than the CAIR threshold for significant contribution, it does not follow that they should be made equivalent (70 FR 25191; May 12, 2005).

c. Comments on the Rounding Conventions for $PM_{2.5}$

In the final Transport Rule, EPA is using two-digit values for the $PM_{2.5}$ thresholds. Some commenters suggested that EPA should use the same rounding convention for annual $PM_{2.5}$ used in CAIR; that is, the threshold should be 0.2 $\mu g/m^3$ rather than 0.15 $\mu g/m^3$. The reasons for EPA's decision are below.

The rationale for the single digit value for the final CAIR rule was that a single digit is consistent with the EPA monitoring data reporting requirements in Part 50, Appendix N, section 4.3. These reporting requirements specify that design values for the annual $PM_{2.5}$ standard shall be rounded to the tenths place (decimals 0.05 and greater are rounded up to the next 0.1, and any decimal lower than 0.05 is rounded down to the nearest 0.1).

Because the design value is to be reported only to the nearest 0.1 $\mu g/m^3$, EPA deemed it preferable for the final CAIR to select the threshold value at the nearest 0.1 $\mu g/m^3$ as well, and hence one percent of the 15 $\mu g/m^3$, rounded to the nearest 0.1 $\mu g/m^3$ became 0.2 $\mu g/m^3$.

The reporting requirements in section Part 50, Appendix N, section 4.3 for the 24-hour $PM_{2.5}$ standard state that design values for this standard shall be rounded to the nearest 1 $\mu g/m^3$ (decimals 0.5 and greater are rounded up to the nearest whole number, and any decimal lower than 0.5 is rounded down to the nearest whole number).

If the approach used in CAIR were to be used to establish an air quality threshold for the 24-hour $PM_{2.5}$ NAAQS (which CAIR did not address), the resulting threshold would be zero. One percent of the 24-hour standard is 0.35 $\mu g/m^3$, and rounding to the nearest whole number would yield an air quality threshold of zero. Thus if we were to apply the same rationale used to develop the annual $PM_{2.5}$ threshold for the final CAIR, there would be no air quality threshold for 24-hour $PM_{2.5}$, which EPA believes to be counter-intuitive and unworkable as an approach for assessing interstate contributions.

Therefore, for this rule, EPA proposed and is now finalizing an approach that decouples the precision of the air quality thresholds from the monitoring reporting requirements, and uses 2-digit values representing one percent of the $PM_{2.5}$ NAAQS; that is, 0.15 $\mu g/m^3$ for the annual standard, and 0.35 $\mu g/m^3$ for the 24-hour standard. EPA believes there are a number of considerations favoring this approach. First, it provides for a consistent approach for the annual and 24-hour standards. Second, the

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approach is readily applicable to any current and future NAAQS and would automatically adjust the stringency of the transport threshold to maintain a constant relationship with the stringency of the relevant NAAQS as they are revised. The CAIR approach would not allow for this continuity: For example, if EPA were to retain the CAIR approach for the annual standard, any future lowering of the $PM_{2.5}$ NAAQS to below 15 μg/m^3 would reduce the air quality threshold to the same outcome: 0.1 μg/m^3. This would occur because any value less than 0.15 μg/m^3 would round to 0.1 μg/m^3 (assuming EPA would not round down to zero for the reasons described above), which means that the air quality threshold would have a different relative stringency to each possible future NAAQS value. For the above reasons, EPA believes the use of two-digit thresholds for both annual $PM_{2.5}$ and 24-hour $PM_{2.5}$ in the final rule is both reasonable and appropriate. The departure from the approach used for annual $PM_{2.5}$ in CAIR is appropriate given the additional considerations that were not in existence at the time of the final CAIR, and the importance of using a consistent approach to developing air quality thresholds for all NAAQS addressed by this rule as well as future NAAQS considered in future transport-related actions.

Some of these commenters suggested using the CAIR rounding conventions coupled with use of a 1-digit threshold of 0.4 μg/m^3 for 24-hour $PM_{2.5}$. EPA considered the approach suggested by commenters, but determined that the proposed approach is more appropriate. First, adhering to the rounding conventions used for CAIR for annual $PM_{2.5}$ is not workable for the 24-hour standard because the rounding convention would yield a threshold of zero. Rounding alternatively to 0.4 μg/m^3 would require EPA to find a basis for rounding the threshold to the nearest 0.1 μg/m^3 instead of using a strict application of 1 percent; we do not see any basis for such rounding at this time.

d. Comments Related to the Multi-Factor Test EPA Used for Ozone in CAIR

Some commenters suggested that, for ozone, EPA should use the multiple-metric test we used for CAIR, and not a simple threshold based on 1 percent of the NAAQS. With respect to ozone, EPA proposed in the Transport Rule to take a more straightforward approach to air quality thresholds than the multi-factor approaches used for the NO_X SIP Call and the CAIR. As proposed, EPA is using a contribution metric that is calculated based on the multi-day average contribution. This metric is compared to one percent of the 1997 8-hour ozone standard of 0.08 ppm. Under this approach, one percent of the NAAQS is a value of 0.8 ppb. Contributions of 0.8 ppb and higher are above the threshold; ozone contributions less than 0.8 ppb are below the threshold. In past rulemakings (*e.g.,* CAIR) EPA used multiple ozone metrics, including the average contribution and maximum single day contribution to downwind nonattainment. EPA believes the average contribution (calculated over multiple high ozone days) is a robust metric compared to the maximum contribution on a single day. EPA believes that this approach is preferable because it uses a robust metric, it is consistent with the approach for $PM_{2.5}$, and it provides for a consistent approach that takes into account, and is applicable to, any future ozone standards below 0.08 ppm.

One of these commenters suggested that the 0.8 ppb threshold value was substantially more stringent than the 2 ppb screening test which was a part of the approach used for CAIR. The 1 percent threshold (0.8 ppb) is not substantially more stringent than the previous 2 ppb test because of differences in the metrics used to evaluate contributions against these two levels. The 2 ppb test was evaluated using the highest single day absolute model-predicted downwind contribution from an upwind state. The 1 percent threshold is evaluated based on the average relative downwind impact calculated over multiple days. Therefore, it is appropriate to set a lower concentration threshold for use with the average contribution metric calculated for the Transport Rule. More details on the calculation of the contribution metric can be found in the Air Quality Modeling Final Rule TSD. As noted above, EPA believes that the approach used for the proposed rule provides for a simplified, yet robust approach compared to CAIR. Accordingly, for the final rule we have retained the approach used for the proposal.

One commenter suggested that EPA retain the CAIR multiple-factor approach for ozone, and to apply that same approach to 24-hour $PM_{2.5}$. As noted above, EPA is not retaining this approach for ozone, and for similar reasons we believe a multi-factor approach is not needed for 24-hour $PM_{2.5}$. The approach based on 1 percent of the NAAQS is consistent with the form of the 24-hour standard. In addition, this approach is based on contributions on days with high 24-hour $PM_{2.5}$ predictions and therefore is relevant for characterizing transport during short-term high $PM_{2.5}$ episodic conditions.

e. Comments on the Relationship to Measurement Precision

Other commenters suggested that, as did commenters on the thresholds used in CAIR, EPA should take into consideration the measurement precision of existing $PM_{2.5}$ monitors in setting the thresholds for the Transport Rule. EPA disagrees that monitoring precision is relevant to determining the amount of modeled $PM_{2.5}$ or ozone that should be considered to be a ''contribution'' from upwind states since states are not required to, nor would it be possible for them to, measure their individual state impacts on downwind receptors. The approach for eliminating significant contribution is based on the implementation of enforceable emissions budgets and not on a measurement of ambient air quality. Thus, EPA believes it is a reasonable exercise of its discretion to de-couple monitoring precision from the choice of contribution states.

f. Comments Related to the CAIR Court Decision

Commenters recommended that EPA should have retained the criteria used for CAIR because those values were upheld by the Court. As noted above, EPA could not have used the approach for annual $PM_{2.5}$ that was used in CAIR to develop a 24-hour $PM_{2.5}$ threshold, as that approach would have yielded a threshold value of zero 24-hour $PM_{2.5}$.

Further, nothing in the *North Carolina* opinion suggests that the thresholds and methods used in CAIR were the only possible approaches EPA could have used, that they were preferable to other approaches, or that other alternatives would not be acceptable. Instead, the Court upheld the 0.2 μg/m^3 threshold used for $PM_{2.5}$ on the grounds that it was not ''wholly unsupported by the record'' (*North Carolina,* 531 F.3d at 915). EPA has determined for reasons explained in the record that the thresholds used in this final rule are both reasonable and appropriate for use in this final rule.

2. Approach for Identifying Contributing Upwind States

This section documents the procedures used by EPA to quantify the contribution of emissions in specific upwind states to air quality concentrations in projected 2012 downwind nonattainment and maintenance locations for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. In the

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proposed rule EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on projected downwind nonattainment and maintenance receptors for both $PM_{2.5}$ and 8-hour ozone. In this modeling we tracked the ozone and $PM_{2.5}$ formed from 2012 base case emissions from anthropogenic sources in each upwind state in the 12 km modeling domain. The CAMx Particulate Source Apportionment Technique (PSAT) was used to calculate downwind contributions to nonattainment and maintenance of $PM_{2.5}$. In the PSAT simulation NO_X emissions are tracked to particulate nitrate concentrations, SO_2 emissions are tracked to particulate sulfate concentrations, and primary particulates (organic carbon, elemental carbon, and other $PM_{2.5}$) are tracked as primary particulates. As described earlier in section V.A, the nitrate and sulfate contributions were combined and used to evaluate interstate contributions of $PM_{2.5}$.

The CAMx Ozone Source Apportionment Technique (OSAT) was used to calculate downwind 8-hour ozone contributions to nonattainment and maintenance. OSAT tracks the formation of ozone from NO_X and VOC emissions.

Comment: Three commenters stated that the CAMx source apportionment techniques used for the proposed rule reflect state-of-the science technologies and are appropriate for evaluating interstate transport. One commenter asked that EPA do more to demonstrate that the PSAT and OSAT techniques give reliable answers, although no suggestions were provided on how this might be done. Another commenter said that the results of the contribution analyses were consistent with the results of their scientific research.

Response: EPA is not changing its conclusion that the CAMx source apportionment techniques are appropriate for quantifying interstate transport. The strength of the source apportionment technique is that all modeled ozone and/or $PM_{2.5}$ mass at a given location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources. No commenters provided technically valid analyses indicating that EPA's use of CAMx source apportionment techniques are inappropriate for the purposes of the Transport Rule.

Comment: We received comments that certain states included in the proposed rule should be excluded from the final rule because EPA had overstated the 2012 emissions in these states. Commenter requested that we redo the contribution modeling using 2012 base case emission inventories that are revised based on proposed rule comments. Several commenters also asked that EPA update the contribution modeling analyses using the latest version of CAMx.

Response: In response to these comments, we have rerun our source apportionment modeling for $PM_{2.5}$ and ozone for the 2012 base case using the updated emission inventories described above in section V.C.1 and the latest version of CAMx, version 5.30.

The states EPA analyzed for interstate contributions for ozone and for $PM_{2.5}$ for the final rule are: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland,[31] Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.[32] These are the same states that EPA analyzed for the proposed rule.

For the proposed rule, we used a relative approach for calculating the contributions to downwind nonattainment and maintenance receptors from the outputs of the source apportionment modeling. As part of this approach, the source apportionment predictions are combined with measurement-based concentrations to calculate the contributions from each state to nonattainment and/or maintenance receptors. This is similar to the approach used to calculate future year design values, as described in section V.C.2.

Comment: One commenter said that using the source apportionment modeling predictions in a relative sense strengthens the determination of contributions and addresses an important source of uncertainty. There were no comments that suggested an alternative approach.

[31] As in the proposal, EPA has combined the contributions from Maryland and the District of Columbia as a single entity in our contribution analysis for the final rule. EPA believes that this is a fair representation of emissions for transport analysis because of the small size of the District of Columbia and its close proximity to Maryland. However, the District of Columbia is not included in the Transport Rule due to the significant contribution analysis findings in section VI.D.

[32] There were also several other states that are only partially contained within the 12 km modeling domain (i.e., Colorado, Montana, New Mexico, and Wyoming). However, EPA did not individually track the emissions or assess the contribution from emissions in these states.

Response: For the final Transport Rule we are applying the relative approach developed for the proposed rule to calculate contributions from each state to downwind nonattainment and maintenance receptors.

As noted above, for the final rule we modeled the updated 2012 base case emissions using CAMx v5.30 to determine the contributions from emissions in upwind states to nonattainment and maintenance sites in downwind states. Contributions to nonattainment and maintenance receptors are evaluated independently for each state to determine if the contributions are at or above the threshold criteria.

For each upwind state, the maximum contribution to nonattainment is calculated based on the single largest contribution to a future year (2012) downwind nonattainment receptor. The maximum contribution to maintenance is calculated based on the single largest contribution to a future year (2012) downwind maintenance receptor. Since the contributions are calculated independently for each receptor, the upwind contribution to maintenance can sometimes be larger than the contribution to nonattainment, and vice versa. This also means that maximum contributions to nonattainment can be below the threshold while maximum contributions to maintenance may be at or above the threshold, or vice versa.

V.D.2.a. Estimated Interstate Contributions to Annual $PM_{2.5}$ and 24-Hour $PM_{2.5}$

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS and the 24-hour $PM_{2.5}$ NAAQS based on modeling updated for the final rule. As described previously in section V.D.1, states which contribute 0.15 μg/m[3] or more to annual $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions large enough to warrant further analysis. For 24-hour $PM_{2.5}$, states which contribute 0.35 μg/m [3] or more to 24-hour $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions to downwind nonattainment and maintenance sites large enough to warrant further analysis.

For annual $PM_{2.5}$, we calculated each state's contribution to each of the 12 monitoring sites that are projected to be nonattainment and each of the 4 sites that are projected to have maintenance problems for the annual $PM_{2.5}$ NAAQS in the 2012 base case. A detailed

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description of the calculations can be found in the Air Quality Modeling Final Rule TSD. The largest contribution from each state to annual $PM_{2.5}$ nonattainment in downwind sites is provided in Table V.D–1. The Largest Contribution from Each State to Annual $PM_{2.5}$ maintenance in downwind sites is also provided in Table V.D–1. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS are provided in the Air Quality Modeling Final Rule TSD.

TABLE V.D–1—LARGEST CONTRIBUTION TO DOWNWIND ANNUAL $PM_{2.5}$ (μG/M³) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind state	Largest downwind contribution to non-attainment for annual $PM_{2.5}$ (μg/m³)	Largest downwind contribution to maintenance for annual $PM_{2.5}$ (μg/m³)
Alabama	0.51	0.19
Arkansas	0.10	0.04
Connecticut	0.00	0.00
Delaware	0.00	0.00
Florida	0.08	0.01
Georgia	0.46	0.13
Illinois	0.50	0.65
Indiana	1.34	1.27
Iowa	0.26	0.14
Kansas	0.09	0.04
Kentucky	0.94	0.81
Louisiana	0.09	0.03
Maine	0.00	0.00
Maryland	0.15	0.06
Massachusetts	0.00	0.00
Michigan	0.64	0.64
Minnesota	0.14	0.09
Mississippi	0.05	0.01
Missouri	1.22	0.27
Nebraska	0.06	0.03
New Hampshire	0.00	0.00
New Jersey	0.02	0.01
New York	0.21	0.21
North Carolina	0.20	0.06
North Dakota	0.06	0.04
Ohio	1.34	0.94
Oklahoma	0.08	0.03
Pennsylvania	0.54	0.54
Rhode Island	0.00	0.00
South Carolina	0.24	0.04
South Dakota	0.03	0.01
Tennessee	0.32	0.32
Texas	0.18	0.07
Vermont	0.00	0.00
Virginia	0.12	0.06
West Virginia	0.95	0.40
Wisconsin	0.22	0.19

Based on the state-by-state contribution analysis, there are 18 states [33] which contribute 0.15 μg/m³ or more to downwind annual $PM_{2.5}$ nonattainment. These states are: Alabama, Georgia, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, West Virginia, and Wisconsin. In Table V.D–2, we provide a list of the downwind nonattainment sites to which each upwind state contributes 0.15 μg/m³ or more (*i.e.,* the upwind state to downwind nonattainment ''linkages'').

There are 12 states which contribute 0.15 μg/m³ or more to downwind annual $PM_{2.5}$ maintenance. These states are: Alabama, Illinois, Indiana, Kentucky, Michigan, Missouri, New York, Ohio, Pennsylvania, Tennessee, West Virginia, and Wisconsin. In Table V.D–3, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.15 μg/m³ or more (*i.e.,* the upwind state to downwind maintenance ''linkages'').

[33] As in the proposal, EPA has combined the contributions from Maryland and the District of Columbia as a single entity in our contribution analysis for the final rule. EPA believes that this is a fair representation of emissions for transport analysis because of the small size of the District of Columbia and its close proximity to Maryland. However, the District of Columbia is not included in the Transport Rule due to the significant contribution analysis findings in section VI.D.

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TABLE V.D–2—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind state	Downwind receptor sites			
Alabama	Fulton, GA (131210039)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001).
Georgia	Jefferson, AL (10730023)	Jefferson, AL (10732003).		
Illinois	Jefferson, AL (10732003)	Fulton, GA (131210039)	Wayne, MI (261630033)	Cuyahoga, OH (390350038).
	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042).
	Hamilton, OH (390618001)	Allegheny, PA (420030064).		
Indiana	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Madison, IL (171191007).
	Wayne, MI (261630033)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060).
	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001)	Allegheny, PA (420030064).
Iowa	Madison, IL (171191007).			
Kentucky	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Madison, IL (171191007).
	Wayne, MI (261630033)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060).
	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001)	Allegheny, PA (420030064).
Maryland	Allegheny, PA (420030064).			
Michigan	Madison, IL (171191007)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060).
	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001)	Allegheny, PA (420030064).
Missouri	Madison, IL (171191007)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060).
	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001).	
New York	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Allegheny, PA (420030064).
North Carolina	Fulton, GA (131210039).			
Ohio	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Madison, IL (171191007).
	Wayne, MI (261630033)	Allegheny, PA (420030064).		
Pennsylvania	Fulton, GA (131210039)	Wayne, MI (261630033)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045).
	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001).
South Carolina	Fulton, GA (131210039).			
Tennessee	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Madison, IL (171191007).
	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001).	
Texas	Madison, IL (171191007).			
West Virginia	Fulton, GA (131210039)	Wayne, MI (261630033)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045).
	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390618001).
	Allegheny, PA (420030064).			
Wisconsin	Madison, IL (171191007)	Wayne, MI (261630033)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390618001).	

TABLE V.D–3—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind state	Downwind receptor sites			
Alabama	Marion, IN (180970081)	Marion, IN (180970083)	Hamilton, OH (390617001).	
Illinois	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
Indiana	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).		
Kentucky	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
Michigan	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
Missouri	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
New York	Cuyahoga, OH (390350065).			
Ohio	Marion, IN (180970081)	Marion, IN (180970083).		
Pennsylvania	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
Tennessee	Marion, IN (180970081)	Marion, IN (180970083)	Hamilton, OH (390617001).	
West Virginia	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).
Wisconsin	Marion, IN (180970081)	Marion, IN (180970083)	Cuyahoga, OH (390350065)	Hamilton, OH (390617001).

For 24-hour $PM_{2.5}$, we calculated each state's contribution to each of the 20 monitoring sites that are projected to be nonattainment and each of the 21 sites that are projected to have maintenance problems for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case. A detailed description of the calculations can be found in the Air Quality Modeling Final Rule TSD. The largest contribution from each state to 24-hour $PM_{2.5}$ nonattainment in downwind sites is provided in Table V.D–4. The largest contribution from each state to 24-hour $PM_{2.5}$ maintenance in downwind sites is also provided in Table V.D–4. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 24-hour $PM_{2.5}$ NAAQS are provided in the Air Quality Modeling Final Rule TSD.

TABLE V.D–4—LARGEST CONTRIBUTION TO DOWNWIND 24-HOUR $PM_{2.5}$ ($\mu G/M^3$) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind state	Largest downwind contribution to non-attainment for 24-hour $PM_{2.5}$ ($\mu g/m^3$)	Largest downwind contribution to maintenance for 24-hour $PM_{2.5}$ ($\mu g/m^3$)
Alabama	0.51	0.42

TABLE V.D–4—LARGEST CONTRIBUTION TO DOWNWIND 24-HOUR $PM_{2.5}$ (μG/M³) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind state	Largest downwind contribution to non-attainment for 24-hour $PM_{2.5}$ (μg/m³)	Largest downwind contribution to maintenance for 24-hour $PM_{2.5}$ (μg/m³)
Arkansas	0.24	0.23
Connecticut	0.10	0.18
Delaware	0.22	0.20
Florida	0.07	0.03
Georgia	1.10	0.92
Illinois	3.72	5.70
Indiana	3.56	5.15
Iowa	0.82	1.55
Kansas	0.37	0.81
Kentucky	4.38	3.58
Louisiana	0.11	0.13
Maine	0.06	0.10
Maryland	2.83	2.11
Massachusetts	0.19	0.30
Michigan	1.86	2.03
Minnesota	0.61	1.01
Mississippi	0.06	0.07
Missouri	3.73	3.71
Nebraska	0.24	0.52
New Hampshire	0.05	0.10
New Jersey	0.68	0.75
New York	0.83	1.34
North Carolina	0.40	0.38
North Dakota	0.21	0.33
Ohio	5.85	4.74
Oklahoma	0.17	0.20
Pennsylvania	2.85	2.29
Rhode Island	0.02	0.03
South Carolina	0.29	0.25
South Dakota	0.10	0.17
Tennessee	1.38	1.30
Texas	0.37	0.33
Vermont	0.03	0.05
Virginia	1.21	1.01
West Virginia	4.02	3.33
Wisconsin	0.69	0.97

Based on the state-by-state contribution analysis, there are 21 states[34] which contribute 0.35 μg/m³ or more to downwind 24-hour $PM_{2.5}$ nonattainment. These states are: Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. In Table V.D–5, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.35 μg/m³ or more (*i.e.,* the upwind state to downwind nonattainment ''linkages'').

There are 21 states which contribute 0.35 μg/m³ or more to downwind 24-hour $PM_{2.5}$ maintenance. These states are: Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table V.D–6, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.35 μg/m³ or more (*i.e.,* the upwind state to downwind maintenance ''linkages'').

TABLE V.D–5—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE ''LINKAGES'' FOR 24-HOUR $PM_{2.5}$

Upwind state	Downwind receptor sites			
Alabama	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970081).	
Georgia	Jefferson, AL (10730023).			
Illinois	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970081)	St Clair, MI (261470005).
	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033).
	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420030093).
	Allegheny, PA (420030116)	Beaver, PA (420070014)	Brooke, WV (540090011)	Milwaukee, WI (550790043).

[34] As in the proposal, EPA has combined the contributions from Maryland and the District of Columbia as a single entity in our contribution analysis for the final rule. EPA believes that this is a fair representation of emissions for transport analysis because of the small size of the District of Columbia and its close proximity to Maryland. However, the District of Columbia is not included in the Transport Rule due to the significant contribution analysis findings in section VI.D.

TABLE V.D–5—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Indiana	Jefferson, AL (10730023)	Cook, IL (170311016)	Madison, IL (171191007)	St Clair, MI (261470005).
	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033).
	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420030093).
	Allegheny, PA (420030116)	Beaver, PA (420070014)	Brooke, WV (540090011)	Milwaukee, WI (550790043).
Iowa	Cook, IL (170311016)	Madison, IL (171191007)	Milwaukee, WI (550790043).	
Kansas	Madison, IL (171191007).			
Kentucky	Jefferson, AL (10730023)	Cook, IL (170311016)	Madison, IL (171191007)	Marion, IN (180970043).
	Marion, IN (180970066)	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015).
	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Cuyahoga, OH (390350038).
	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116).
	Beaver, PA (420070014)	Brooke, WV (540090011)	Milwaukee, WI (550790043).	
Maryland	Cuyahoga, OH (390350038)	Lancaster, PA (420710007).		
Michigan	Cook, IL (170311016)	Madison, IL (171191007)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350060).
	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Beaver, PA (420070014)	Brooke, WV (540090011).
	Milwaukee, WI (550790043).			
Minnesota	Milwaukee, WI (550790043).			
Missouri	Cook, IL (170311016)	Madison, IL (171191007)	Marion, IN (180970043)	Marion, IN (180970066).
	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015)	Allegheny, PA (420030064).
	Allegheny, PA (420030116)	Beaver, PA (420070014)	Milwaukee, WI (550790043).	
New Jersey	Lancaster, PA (420710007).			
New York	St Clair, MI (261470005)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033).
	Cuyahoga, OH (390350060)	Lancaster, PA (420710007).		
North Carolina	Lancaster, PA (420710007).			
Ohio	Jefferson, AL (10730023)	Cook, IL (170311016)	Madison, IL (171191007)	Marion, IN (180970043).
	Marion, IN (180970066)	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015)
	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Allegheny, PA (420030064).
	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Beaver, PA (420070014)	Lancaster, PA (420710007).
	Brooke, WV (540090011)	Milwaukee, WI (550790043).		
Pennsylvania	Jefferson, AL (10730023)	Cook, IL (170311016)	Madison, IL (171191007)	Marion, IN (180970043).
	Marion, IN (180970066)	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015).
	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Cuyahoga, OH (390350038).
	Cuyahoga, OH (390350060)	Brooke, WV (540090011)	Milwaukee, WI (550790043)..	
Tennessee	Jefferson, AL (10730023)	Madison, IL (171191007)	Marion, IN (180970043)	Marion, IN (180970066).
	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015)	Wayne, MI (261630033).
	Cuyahoga, OH (390350038)	Allegheny, PA (420030116).		
Texas	Madison, IL (171191007).			
Virginia	Lancaster, PA (420710007).			
West Virginia	Jefferson, AL (10730023)	Cook, IL (170311016)	Madison, IL (171191007)	Marion, IN (180970043).
	Marion, IN (180970066)	Marion, IN (180970081)	St Clair, MI (261470005)	Wayne, MI (261630015).
	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Cuyahoga, OH (390350038).
	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116).
	Beaver, PA (420070014)	Lancaster, PA (420710007)	Milwaukee, WI (550790043).	
Wisconsin	Cook, IL (170311016)	Wayne, MI (261630019)	Wayne, MI (261630033).	

TABLE V.D–6—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$

Upwind state	Downwind receptor sites			
Alabama	Washtenaw, MI (261610008)	Butler, OH (390170003)	Montgomery, OH (391130032).	
Georgia	Jefferson, AL (10732003).			
Illinois	Lake, IN (180890022)	Lake, IN (180890026)	Washtenaw, MI (261610008)	Butler, OH (390170003).
	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	Hamilton, OH (390618001)	Jefferson, OH (390811001).
	Montgomery, OH (391130032).	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Allegheny, PA (420033007).
	York, PA (421330008)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).	
Indiana	Jefferson, AL (10732003)	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301).
	Cook, IL (170316005)	Madison, IL (171190023)	Washtenaw, MI (261610008)	Butler, OH (390170003).
	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	Hamilton, OH (390618001)	Jefferson, OH (390811001).
	Montgomery, OH (391130032).	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Allegheny, PA (420033007).
	York, PA (421330008)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).	
Iowa	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301)	Cook, IL (170316005).
	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026)	Milwaukee, WI (550790010).
	Milwaukee, WI (550790026).			
Kansas	Cook, IL (170310052)	Cook, IL (170316005)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).
Kentucky	Jefferson, AL (10732003)	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301).
	Cook, IL (170316005)	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026).
	Washtenaw, MI (261610008)	Butler, OH (390170003)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065).
	Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032).	Allegheny, PA (420031008).
	Allegheny, PA (420031301)	Allegheny, PA (420033007)	York, PA (421330008)	Milwaukee, WI (550790010).
	Milwaukee, WI (550790026).			

TABLE V.D–6—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Maryland	York, PA (421330008).			
Michigan	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301)	Cook, IL (170316005).
	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026)	Butler, OH (390170003).
	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	Hamilton, OH (390618001)	Jefferson, OH (390811001).
	Montgomery, OH (391130032).	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Allegheny, PA (420033007).
	York, PA (421330008)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).	
Minnesota	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).		
Missouri	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301)	Cook, IL (170316005).
	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026)	Washtenaw, MI (261610008).
	Butler, OH (390170003)	Hamilton, OH (390618001)	Montgomery, OH (391130032).	Allegheny, PA (420031008).
	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).		
Nebraska	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).		
New Jersey	York, PA (421330008).			
New York	Washtenaw, MI (261610008)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	York, PA (421330008).
North Carolina	York, PA (421330008).			
Ohio	Jefferson, AL (10732003)	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301).
	Cook, IL (170316005)	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026).
	Washtenaw, MI (261610008)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Allegheny, PA (420033007).
	York, PA (421330008)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).	
Pennsylvania	Jefferson, AL (10732003)	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301).
	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026)	Washtenaw, MI (261610008).
	Butler, OH (390170003)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	Hamilton, OH (390618001).
	Jefferson, OH (390811001)	Montgomery, OH (391130032).	Milwaukee, WI (550790010)	Milwaukee, WI (550790026).
Tennessee	Jefferson, AL (10732003)	Madison, IL (171190023)	Washtenaw, MI (261610008)	Butler, OH (390170003).
	Cuyahoga, OH (390350065)	Hamilton, OH (390618001)	Montgomery, OH (391130032).	
Virginia	York, PA (421330008).			
West Virginia	Jefferson, AL (10732003)	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301).
	Madison, IL (171190023)	Lake, IN (180890022)	Lake, IN (180890026)	Washtenaw, MI (261610008).
	Butler, OH (390170003)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350065)	Hamilton, OH (390618001).
	Jefferson, OH (390811001)	Montgomery, OH (391130032).	Allegheny, PA (420031008)	Allegheny, PA (420031301).
	Allegheny, PA (420033007)	York, PA (421330008)	Milwaukee, WI (550790010).	
Wisconsin	Cook, IL (170310052)	Cook, IL (170312001)	Cook, IL (170313301)	Cook, IL (170316005).
	Lake, IN (180890022)	Lake, IN (180890026).		

b. Estimated Interstate Contributions to 8-Hour Ozone

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the ozone NAAQS. As described previously in section V.D.1, states which contribute 0.8 ppb or more to 8-hour ozone nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis.

We calculated each state's contribution to ozone at each of the 4 monitoring sites that are projected to be nonattainment and each of 6 [35] sites that are projected to have maintenance problems for the 8-hour ozone NAAQS in the 2012 base case. A detailed description of the calculations can be found in the Air Quality Modeling Final Rule TSD. The largest contribution from each state to 8-hour ozone nonattainment in downwind sites is provided in Table V.D–7. The largest contribution from each state to 8-hour ozone maintenance in downwind sites is also provided in Table V.D.2–7. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 8-hour ozone NAAQS are provided in the Air Quality Modeling Final Rule TSD.

TABLE V.D–7—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind state	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Alabama	4.0	2.8
Arkansas	2.1	2.0

[35] There are 6 additional sites with projected 2012 nonattainment or maintenance (Harris Co., Texas sites 482010024, 482010062, 482010066, 482011015, 482011035, and 482011039) for which there are less than 5 days with 8-hour ozone predictions of at least 70 ppb. Thus, we did not calculate contributions for these 6 sites.

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TABLE V.D–7—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind state	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Connecticut	0.0	0.2
Delaware	0.0	0.6
Florida	0.5	3.6
Georgia	1.6	2.8
Illinois	1.9	26.8
Indiana	1.3	9.4
Iowa	0.6	0.9
Kansas	0.5	1.0
Kentucky	1.6	1.6
Louisiana	8.0	11.1
Maine	0.0	0.0
Maryland	0.0	2.7
Massachusetts	0.0	0.6
Michigan	0.0	0.9
Minnesota	0.3	0.2
Mississippi	4.0	3.3
Missouri	1.1	4.8
Nebraska	0.2	0.2
New Hampshire	0.0	0.1
New Jersey	0.0	11.5
New York	0.0	18.8
North Carolina	0.5	1.3
North Dakota	0.2	0.1
Ohio	0.1	3.2
Oklahoma	0.3	2.8
Pennsylvania	0.1	8.2
Rhode Island	0.0	0.0
South Carolina	0.4	0.9
South Dakota	0.1	0.1
Tennessee	2.2	1.1
Texas	3.9	1.9
Vermont	0.0	0.0
Virginia	0.2	8.2
West Virginia	0.0	2.8
Wisconsin	0.2	2.2

Based on the state-by-state contribution analysis, there are 11 states that contribute 0.8 ppb or more to downwind 8-hour ozone nonattainment. These states are: Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, Tennessee, and Texas.[36] In Table V.D–8, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (*i.e.,* the upwind state to downwind nonattainment ''linkages'').

There are 26 states [37] which contribute 0.8 ppb or more to downwind 8-hour ozone maintenance. These states are: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.[38] In Table V.D.2–9, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (*i.e.,* the upwind state to downwind nonattainment ''linkages'').

[36] As discussed in section III, EPA is issuing a supplemental notice of proposed rulemaking to provide an opportunity for public comment on our conclusion that emissions from Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin significantly contribute to nonattainment or interfere with maintenance of the 1997 ozone NAAQS in other states.

[37] As in the proposal, EPA has combined the contributions from Maryland and the District of Columbia as a single entity in our contribution analysis for the final rule. EPA believes that this is a fair representation of emissions for transport analysis because of the small size of the District of Columbia and its close proximity to Maryland. However, the District of Columbia is not included in the Transport Rule due to the significant contribution analysis findings in section VI.D.

[38] As discussed in section III, EPA is issuing a supplemental notice of proposed rulemaking to provide an opportunity for public comment on our conclusion that emissions from Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin significantly contribute to nonattainment or interfere with maintenance of the 1997 ozone NAAQS in other states.

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TABLE V.D–8—UPWIND STATE TO DOWNWIND NONATTAINMENT "LINKAGES" FOR 8-HOUR OZONE

Upwind state	Downwind receptor sites			
Alabama	East Baton Rouge, LA (220330003).	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).
Arkansas	East Baton Rouge, LA (220330003).	Brazoria, TX (480391004).		
Georgia	East Baton Rouge, LA (220330003).	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).
Illinois	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).	
Indiana	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).	
Kentucky	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).	
Louisiana	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).	
Mississippi	East Baton Rouge, LA (220330003).	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).
Missouri	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).	
Tennessee	East Baton Rouge, LA (220330003).	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055).
Texas	East Baton Rouge, LA (220330003).			

TABLE V.D–9—UPWIND STATE TO DOWNWIND MAINTENANCE "LINKAGES" FOR 8-HOUR OZONE

Upwind state	Downwind receptor sites			
Alabama	Harris, TX (482010029)	Harris, TX (482011050).		
Arkansas	Allegan, MI (260050003).			
Florida	Harris, TX (482010029)	Harris, TX (482011050).		
Georgia	Harris, TX (482010029)	Harris, TX (482011050).		
Illinois	Fairfield, CT (90011123)	Allegan, MI (260050003)	Harris, TX (482011050).	
Indiana	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001)	Allegan, MI (260050003).
Iowa	Allegan, MI (260050003).			
Kansas	Allegan, MI (260050003).			
Kentucky	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001)	Harris, TX (482011050).
Louisiana	Harris, TX (482010029)	Harris, TX (482011050).		
Maryland	Fairfield, CT (90011123)	New Haven, CT (90093002).		
Michigan	Harford, MD (240251001).			
Mississippi	Harris, TX (482010029)	Harris, TX (482011050).		
Missouri	Allegan, MI (260050003).			
New Jersey	Fairfield, CT (90011123)	New Haven, CT (90093002).		
New York	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001).	
North Carolina	New Haven, CT (90093002)	Harford, MD (240251001).		
Ohio	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001).	
Oklahoma	Allegan, MI (260050003).			
Pennsylvania	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001).	
South Carolina	Harris, TX (482010029).			
Tennessee	Fairfield, CT (90011123)	Harford, MD (240251001)	Harris, TX (482011050).	
Texas	Allegan, MI (260050003).			
Virginia	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001).	
West Virginia	Fairfield, CT (90011123)	New Haven, CT (90093002)	Harford, MD (240251001).	
Wisconsin	Allegan, MI (260050003).			

VI. Quantification of State Emission Reductions Required

A. Cost and Air Quality Structure for Defining Reductions

1. Summary

Section V, above, describes EPA's approach to identifying upwind states with air quality contributions that meet or exceed the air quality thresholds discussed therein for each of the NAAQS addressed in this rule. A state is covered by the Transport Rule if its contributions meet or exceed one of those air quality thresholds and the Agency identifies, using the cost- and air quality-based approach described below, emissions within the state that constitute the state's significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone, 1997 $PM_{2.5}$ or 2006 $PM_{2.5}$ NAAQS.

In this section, EPA explains its final cost- and air quality-based approach to quantify the amount of emissions that represent significant contribution to nonattainment and interference with maintenance for each state. EPA then applies that approach for the three different NAAQS being addressed in this rule: The 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS. EPA believes that the methodology finalized could also be used to address transport concerns under other NAAQS, including future revisions to the ozone and $PM_{2.5}$ NAAQS.

EPA applies the methodology described herein to fully quantify the emissions that constitute each covered state's significant contribution to nonattainment and interference with maintenance with respect to the 1997 annual $PM_{2.5}$ and the 2006 24-hour $PM_{2.5}$ NAAQS. The FIPs with respect to the annual and 24-hour $PM_{2.5}$ NAAQS that are finalized in this action ensure that all such emissions are prohibited. Each such FIP thus fully satisfies the requirements of 110(a)(2)(D)(i)(I) with

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respect to the annual and/or 24-hour $PM_{2.5}$ NAAQS for the covered state.

EPA also applies the methodology to quantify significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone NAAQS. However, we have not been able to fully quantify such emissions for all covered states. In this action, EPA fully quantifies the significant contribution to nonattainment and interference with maintenance for 15 states. We finalize FIPs with respect to the 1997 ozone standards for 10 of these 15 states (Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Virginia, and West Virginia). We are also publishing a supplemental notice of rulemaking to take comment on whether FIPs should be finalized for the remaining 5 states (Iowa, Kansas, Michigan, Oklahoma, and Wisconsin). The FIPs for these 10 states (and the FIPs for the remaining 5 states, if finalized) fully satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS for the covered state.

In addition, we apply the methodology described herein to quantify, for 11 additional states, ozone-season NO_X emission reductions that are necessary but may not be sufficient to eliminate all significant contribution to nonattainment and interference with maintenance in other states. We finalize FIPs with respect to the 1997 ozone standards for 10 of these 11 states (Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Tennessee, and Texas). We are also publishing a supplemental notice of rulemaking to take comment on whether FIPs should be finalized for the remaining state (Missouri). The FIPs for these 10 states (and the FIP for the remaining state, if finalized) make measurable progress toward satisfying the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS in each covered state. To the extent that significant contribution to nonattainment and interference with maintenance is not entirely eliminated for the 1997 ozone NAAQS through today's action, EPA will address these instances in a future rulemaking. This is further explained in section VI.D.

With respect to the 1997 annual $PM_{2.5}$ NAAQS, this rule finds that 18 states have SO_2 and NO_X emission reduction responsibilities. EPA also finds that 21 states have SO_2 and NO_X emission reduction responsibilities with respect to the 2006 24-hour $PM_{2.5}$ NAAQS. There are a total of 23 states that have SO_2 and NO_X emission reduction responsibilities for one or both of the above $PM_{2.5}$ NAAQS. We apply the methodology to quantify emission reductions that these states must achieve to eliminate the state's significant contribution to nonattainment and interference with maintenance. The states are listed in Table III–1 in section III of this preamble.

This rule will prohibit all significant contribution to nonattainment and interference with maintenance with respect to the annual and 24-hour $PM_{2.5}$. In addition, it will resolve air quality issues at most nonattainment and maintenance receptors identified by EPA. EPA projects that unresolved nonattainment and maintenance issues will remain in only a few downwind states after promulgation and implementation of the Transport Rule. For the annual $PM_{2.5}$ standard, EPA projects that this rule will help assure that all areas in the east fully resolve their nonattainment and maintenance concerns. This rule will also help a number of areas achieve the standard earlier than they may have otherwise. For the 2006 24-hour $PM_{2.5}$ NAAQS, one area is projected to remain in nonattainment (Liberty-Clairton) and three areas are projected to have remaining maintenance concerns after imposition of the Transport Rule (Chicago,[39] Detroit, and Lancaster County).[40]

The methodology provides similar assistance for ozone, assuring upwind reductions that will assist downwind states in controlling ozone pollution. It reduces ozone concentration levels in 2012 and helps assure that all but two downwind areas fully resolve their nonattainment and maintenance problems with the 1997 ozone NAAQS by 2014. While Houston is projected to still face nonattainment and Baton Rouge is projected to still face maintenance concerns with the 1997 ozone NAAQS, the Transport Rule improves air quality in these two areas and provides both health benefits and assistance for these local areas in meeting the NAAQS requirements. For reasons explained below, EPA will conduct further analysis in a subsequent transport-related rulemaking to determine whether further upwind state reductions are warranted to assist attainment and maintenance of the ozone NAAQS in Houston and Baton Rouge areas.

When EPA proposed this air-quality and cost-based multi-factor approach to identify emissions that constitute significant contribution to nonattainment and interference with maintenance from upwind states with respect to the 1997 ozone, annual $PM_{2.5}$, and 2006 24-hour $PM_{2.5}$ NAAQS, the Agency indicated that the approach was designed to be applicable to both current and potential future ozone and $PM_{2.5}$ NAAQS (75 FR 45214). EPA believes that the final Transport Rule demonstrates the value of this approach for addressing the role of interstate transport of air pollution in communities' ability to comply with current and future NAAQS. EPA believes that the Transport Rule's approach of using air-quality thresholds to determine upwind-to-downwind-state linkages and using the cost- and air quality-based multi-factor approach to quantify significant contribution to nonattainment and interference with maintenance (*i.e.,* to determine the specific amount of emissions that each upwind state must reduce) could serve as a precedent for quantifying upwind state emission reduction responsibilities with respect to potential future NAAQS.

One commenter suggested that the rule could set a flawed precedent for future transport analyses and remedies, as it does not fully eliminate the prohibited emissions in every upwind state. EPA disagrees with this characterization of the Transport Rule. EPA notes that the partial determination of significant contribution to nonattainment and interference with maintenance for certain upwind states in the Transport Rule with respect to the ozone NAAQS is not a function of the multi-factor approach itself, but is instead a function of its limited application in this rulemaking to identify emission reductions from a single source category (EGUs). In fact, the Transport Rule's approach itself allowed EPA to determine for which upwind states we have identified all emissions that constitute significant contribution to nonattainment and interference with maintenance, and for which upwind states we have identified emissions that are necessary but may not be sufficient to eliminate the prohibited emissions. As EPA explained at proposal, developing the additional information needed to consider NO_X emissions from non-EGU source categories in order to fully quantify upwind state responsibility with respect to the 1997 ozone NAAQS would

[39] This area is not currently designated as nonattainment for the 24-hour $PM_{2.5}$ standard. EPA is portraying the receptors and counties in this area as a single 24-hour maintenance area based on the annual $PM_{2.5}$ nonattainment designation of Chicago-Gary-Lake County, IL-IN.

[40] In the Transport Rule proposal, EPA noted that the Liberty-Clairton receptor in Allegheny county was significantly impacted by local emissions from a sizeable coke production facility and other nearby sources (75 FR 45281).

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substantially delay promulgation of the Transport Rule. EPA explained that we do not believe that effort should delay the emission reductions and large health benefits this final rule will deliver (75 FR 45213). EPA further explained that we believe it is likely that the Agency can provide the greatest assistance to states in addressing transported pollution by issuing a separate (subsequent) rule to address additional reductions that may be necessary to fully eliminate upwind state responsibility with respect to the 1997 ozone NAAQS (75 FR 45288). Thus, EPA decided to promulgate the Transport Rule as quickly as possible. EPA anticipates that application of this air-quality and cost-based multi-factor approach to a broader set of source categories in a subsequent rulemaking will identify any remaining prohibited emissions in the upwind states for which the Transport Rule may not fully eliminate those emissions with respect to the 1997 ozone NAAQS.

2. Background

After using air quality analysis to identify upwind states that are ''linked'' to downwind air quality monitoring sites with nonattainment and maintenance problems through contribution of at least one percent of the relevant NAAQS, EPA quantifies the portion of each state's contribution that constitutes its ''significant contribution'' or ''interference with maintenance.''

This section describes the methodology developed by EPA for this analysis and then explains how that methodology is applied to measure significant contribution to nonattainment and interference with maintenance with respect to the NAAQS of concern. For this portion of the analysis, EPA expands upon the methodology used in the NO_X SIP Call and CAIR but modifies it in important respects. In the NO_X SIP Call and CAIR, EPA's methodology defined significant contribution as those emissions that could be removed with the use of ''highly cost effective'' controls. In the Transport Rule, rather than relying solely on an analysis of what constitutes ''highly cost effective'' controls, EPA relies on an analysis that accounts for both cost and air quality improvement to identify the portion of a state's contribution that constitutes its significant contribution to nonattainment and interference with maintenance. Furthermore, in response to the Court's opinion in *North Carolina,* EPA has developed an approach which gives independent meaning to the ''interfere with maintenance'' prong of section 110(a)(2)(D)(i)(I).

The methodology takes into account both the D.C. Circuit Court's determination that EPA may consider cost when measuring significant contribution, *Michigan,* 213 F.3d at 679, and its rejection of the manner in which cost was used in the CAIR analysis, *North Carolina,* 531 F.3d at 917. It also recognizes that the Court accepted—but did not require—EPA's use of a single, uniform cost threshold to measure significant contribution. *Michigan,* 213 F.3d at 679.

As EPA discussed at length in the Transport Rule proposal, using both air quality and cost factors allows EPA to consider the full range of circumstances and state-specific factors that affect the relationship between upwind emissions and downwind nonattainment and maintenance problems (75 FR 45271). For example, considering cost takes into account the extent to which existing plants are already controlled as well as the potential for, and relative difficulty of, additional emission reductions. Therefore, EPA believes that it is appropriate to consider both cost and air quality metrics when quantifying each state's significant contribution.

This methodology is consistent with the statutory mandate in section 110(a)(2)(D)(i)(I) which requires upwind states to prohibit emissions that significantly contribute to nonattainment or interference with maintenance in another state. As discussed in more detail in the proposal, interpreting significant contribution to nonattainment and interference with maintenance inherently involves a decision on how much emissions control responsibility should be assigned to upwind states, and how much responsibility should be left to downwind states. EPA's methodology is intended to ''assign a substantial but reasonable amount of responsibility to upwind states. * * *to control their emissions'' (75 FR 45272). EPA believes that upwind states contributing to downwind state air quality degradation should bear substantial responsibility to control their emissions because of the plain language of the good neighbor provision, the health risks and control cost impacts that upwind emissions cause in the downwind state, and the cumulative impact in the downwind state of emissions from multiple upwind states, and the importance of achieving attainment in downwind states as expeditiously as practicable but no later than specific deadlines as required by the Act. EPA's approach does not shift the responsibility for achieving or maintaining the NAAQS to the upwind state. *See* 75 FR 45272.

The methodology defines each state's significant contribution to nonattainment and interference with maintenance as the emission reductions available at a particular cost threshold in a specific upwind state which effectively address nonattainment and maintenance of the relevant NAAQS in the linked downwind states of concern. Unlike the NO_X SIP Call and CAIR, where EPA's significant contribution analysis had a regional focus, the methodology used in the Transport Rule focuses on state-specific factors. The methodology uses a multi-step process to analyze costs and air quality impacts, identify appropriate cost thresholds, quantify reductions available from EGUs in each state at those thresholds, and consider the impact of variability in EGU operations. There are four steps to this methodology: (1) Identification of each state's emission reductions available at ascending costs per ton as appropriate; (2) assessment of those upwind emission reductions' downwind air quality impacts; (3) identification of upwind ''cost thresholds'' delivering effective emission reductions and downwind air quality improvement; and (4) enshrinement of the upwind emission reductions available at those cost thresholds in state budgets.

In step one, EPA identifies what emission reductions are available at various cost thresholds, quantifying emission reductions that would occur within each state at ascending costs per ton of emission reductions. In other words, EPA determined for specific cost per ton thresholds, the emission reductions that would be achieved in a state if all EGUs greater than 25 MW in that state used all emission controls and emission reduction measures available at that cost threshold. For purposes of this discussion, we refer to these as ''cost curves.''

For this final rule, EPA used updated IPM modeling to conduct a similar cost curve analysis as conducted in the Transport Rule proposal (75 FR 45275). In the proposal, the cost curves only reflected escalating cost for one pollutant while the other pollutant cost was held constant at base case levels (*i.e.,* $0/ton). However, EPA improved the costing analysis for the final rule by identifying upwind emission reductions available as costs were imposed on both SO_2 and NO_X simultaneously for states linked to downwind states on the basis of the $PM_{2.5}$ NAAQS. In other words, the cost curves in the proposal depicted state level emissions when only one pollutant was priced (*i.e.,* NO_X at $500/

ton). Separate cost curves were done for each pollutant. For the final rule, EPA conducted some preliminary cost curve analysis for identifying NO_X thresholds in this manner. However, for the final cost curve analysis, EPA relied on cost curves that reflected state emissions when pollutants were priced simultaneously (*e.g.,* NO_X at $500/ton and SO_2 at $1,600/ton). For reasons described in section VI.B, EPA was able to conduct this type of analysis because the preliminary cost curves specific to annual and ozone-season NO_X suggested little flexibility in adjusting the $500/ton cost thresholds imposed for each. Therefore, EPA was able to hold the cost threshold constant at $500/ton for these pollutants in its examination of SO_2 at various cost thresholds. EPA believes this approach to cost analysis is a better simulation of the Transport Rule's likely impact on covered sources. Under the final Transport Rule, covered sources in states regulated for $PM_{2.5}$ must address compliance requirements for SO_2 and NO_X emissions simultaneously, and this refined approach to cost curve analysis and subsequent air quality analysis better reflects this reality. Section VI.B of this preamble describes the costing analysis in further detail. Also, for more detail on the development of the cost curves, *see* ''Significant Contribution and State Emission Budgets Final Rule TSD'' in the docket for this rule.

Although the cost curves presented in this rule only include EGU reductions, EPA also assessed the cost of SO_2 and NO_X emission reductions available for source categories other than EGUs in the proposed rulemaking. This preliminary assessment in the rule proposal suggested that there likely would be very large emission reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions (75 FR 45272). EPA revisited these non-EGU reduction cost levels in this final rulemaking and verified that there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen ($500/ton for NO_X, $2,300/ton for SO_2).

Further details on EPA's application of cost curves are provided below, in section VI.B.

In step two, EPA uses an air quality assessment tool to estimate the impact that the combined reductions available from upwind contributing states and the downwind receptor state at different cost-per-ton levels would have on air quality at downwind monitoring sites projected to have nonattainment and/or maintenance problems.[41] While less rigorous than the air quality models used for attainment demonstrations, EPA believes this air quality assessment tool (which has been refined since proposal) is acceptable for assessing the impact of numerous options for upwind emission reductions in the process of defining an upwind state's significant contribution to nonattainment and interference with maintenance. It allows the Agency to anticipate specific air quality impacts of many more potential emission reduction scenarios pertinent to the relevant NAAQS than time- and resource-intensive comprehensive air quality modeling would permit.

Further details on EPA's application of step two in this methodology are provided below, in section VI.C.

In step three, EPA examines cost and air quality information to identify ''significant cost thresholds.'' EPA considered a significant cost threshold to be a point along the cost curves where a noticeable change occurred in downwind air quality, such as a point where large upwind emission reductions become available because a certain type of emissions control strategy becomes cost-effective.[42]

This methodology allows EPA, where appropriate, to define multiple cost thresholds that vary for a particular pollutant for different upwind states. As explained in the Transport Rule proposal, EPA does not believe it is required to utilize multiple cost thresholds to regulate upwind emissions for purposes of the mandate in CAA section 110(a)(2)(D), but EPA's multi-factor methodology developed for the Transport Rule to define significant contribution to nonattainment and interference with maintenance allows the Agency to consider whether a single cost threshold or multiple cost thresholds are appropriate for meeting the requirements of CAA section 110(a)(2)(D) relevant to a particular NAAQS (75 FR 45274).

[41] As is discussed in the RIA, EPA also used the CAMx model to perform air quality analysis of its proposed remedy to address significant contribution. Results from this modeling will not exactly correspond to results from the air quality assessment tool both because the inputs to the air quality modeling are different and the sophisticated model more fully accounts for the complex air chemistry interactions. The full air quality modeling looks at the remedy, including reductions in upwind states that do not contribute as well as the impacts of the variability provisions discussed later in this section. It also provides a metric against which to evaluate the air quality assessment tool.

[42] The cost thresholds identified in this rule are specific to the section 110(a)(2)(D)(i)(I) requirements for the states and NAAQS considered in this proposal. They do not represent an agency position on the appropriateness of such cost thresholds for any other application under the Act.

In step four, EPA uses the information regarding emission reductions available in each ''linked'' upwind state at the appropriate cost threshold to form a state ''budget,'' representing the remaining emissions from covered sources for the state in an average year once significant contribution to nonattainment and interference with maintenance have been eliminated; each budget also allows for the identification of an associated variability limit. These budgets and variability limits are used to develop enforceable requirements under the final remedy. The final rule's methodology for identifying state budgets is derived directly from the cost curves and multi-factor analysis EPA uses to determine each state's significant contribution to nonattainment and interference with maintenance. State emission budgets are discussed in section VI.D and the variability limits are discussed in section VI.E.

B. Cost of Available Emission Reductions (Step 1)

This subsection provides more detail on the cost curves that EPA developed to assess the costs of reducing SO_2 and NO_X emissions to address transport related to ozone and $PM_{2.5}$ concentrations (described previously as Step 1). It summarizes the information from the curves and then provides EPA's interpretation of that information. EPA used IPM to develop the EGU cost curves described in this rulemaking. More information can be found regarding EPA's use of IPM for the final Transport Rule in the ''Significant Contribution and State Emission Budgets Final Rule TSD''.

The amount of emission reductions that the cost curves suggest are available at various costs are specific to the 2012 and 2014 time periods. These cost estimates factor in the time interval between rule finalization and compliance periods, existing controls already in place, and controls that could potentially come on line by the start of the compliance period. EPA notes that cost curves are a fluid concept and would vary given different compliance dates.

1. Development of Annual NO_X and Ozone-Season NO_X Cost Curves

EPA conducted preliminary cost curve analysis for annual NO_X and ozone-season NO_X in a similar manner to that used in the proposed rulemaking. That is, the impact of various cost thresholds on emissions was examined individually. For example, state level emissions were examined at cost levels for annual NO_X of $500, $1,000, and

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$2,500/ton while SO_2 was held at base case levels. EPA used this approach to examine NO_X and ozone-season NO_X emission reductions available from EGUs by 2012 and 2014 at various cost levels, reaching to $2,500/ton for annual NO_X and up to $5,000/ton for ozone-season NO_X (in 2007-year dollars). Section VI.D explains why EPA analyzed the $500/ton threshold for annual and ozone-season NO_X. EPA selected two higher cost thresholds to analyze for annual and ozone-season NO_X that provided a reasonable spectrum of emission reduction opportunities from EGUs at higher cost thresholds. Specifically, EPA analyzed these two higher cost thresholds because the first ($1,000/ton) was informative in regards to the additional EGU NO_X emissions reductions available without installation of advanced controls, and the second ($2,500/ton for annual NO_X, $5,000/ton for ozone-season NO_X) was informative in regards to additional EGU reductions available at cost thresholds where advanced NO_X control retrofits are economic for some units. The cost thresholds were only applied to states with air quality contributions that meet or exceed the air quality thresholds as identified in section V.D. For both annual and ozone-season NO_X, EPA did not consider cost thresholds below $500/ton for reasons explained in section VI.D.

EPA observed in the proposal that low-cost NO_X reductions are available at upwind sources with existing pollution control equipment that may not otherwise be operated in the future without the Transport Rule. EPA believes it is appropriate to prohibit any ''linked'' upwind state from potentially increasing its emissions through a failure to operate these existing pollution controls, which could worsen downwind air quality problems. Thus, EPA reflected operation of these controls in all modeling of different cost thresholds (*i.e.,* the modeling assumes year-round operation of post-combustion NO_X controls in covered $PM_{2.5}$ states and ozone-season operation of post-combustion NO_X controls in covered ozone states).

Table VI.B–1 shows the annual NO_X emissions from EGUs at various levels of control cost per ton for 2014. Table VI.B–2 presents the cost curves for ozone-season NO_X emissions from EGUs. As discussed in section VI.D, EPA determined that $500/ton for annual and ozone NO_X was the appropriate cost threshold for this rule (although EPA plans to determine in the future whether a higher cost/ton threshold may be warranted for states contributing to nonattainment or maintenance problems with the 1997 ozone air quality standard projected to remain in two downwind areas).

TABLE VI.B–1—2014 ANNUAL NO_X EMISSIONS FROM FOSSIL-FUEL FIRED EGUS GREATER THAN 25 MW FOR EACH TRANSPORT RULE STATE AT VARIOUS COSTS PER TON

[(2007$) per ton (thousand tons)]

	Base case level	$500	$1,000	$2,500
Alabama	75	72	72	70
Georgia	48	41	41	39
Illinois	55	51	50	49
Indiana	117	108	107	100
Iowa	45	40	39	37
Kansas	32	25	25	23
Kentucky	83	83	81	78
Maryland	17	17	17	17
Michigan	64	61	61	60
Minnesota	38	30	30	30
Missouri	55	54	54	51
Nebraska	43	27	26	21
New Jersey	8	8	8	8
New York	19	19	18	18
North Carolina	46	46	46	44
Ohio	99	95	94	92
Pennsylvania	132	124	124	116
South Carolina	38	38	37	36
Tennessee	29	29	29	29
Texas	141	138	138	136
Virginia	36	35	35	28
West Virginia	64	64	64	61
Wisconsin	37	32	32	31
Total	1,321	1,236	1,229	1,174

TABLE VI.B–2—2012 OZONE-SEASON NO_X EMISSIONS FROM FOSSIL-FUEL FIRED EGUS GREATER THAN 25 MW FOR EACH TRANSPORT RULE STATE AT VARIOUS COSTS

[(2007$) per ton (thousand tons)]

	Base case level	$500	$1,000	$5,000
Alabama	34	34	34	31
Arkansas	15	15	15	14
Florida	42	27	27	24
Georgia	29	28	28	25
Illinois	21	21	21	21
Indiana	47	46	46	43
Kentucky	38	37	36	34

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TABLE VI.B–2—2012 OZONE-SEASON NO_X EMISSIONS FROM FOSSIL-FUEL FIRED EGUS GREATER THAN 25 MW FOR EACH TRANSPORT RULE STATE AT VARIOUS COSTS—Continued

[(2007$) per ton (thousand tons)]

	Base case level	$500	$1,000	$5,000
Louisiana	13	13	13	13
Maryland	7	7	7	7
Mississippi	10	10	10	9
New Jersey	3	3	3	3
New York	8	8	8	8
North Carolina	23	23	23	21
Ohio	42	42	42	38
Pennsylvania	53	53	52	49
South Carolina	15	15	15	14
Tennessee	16	16	15	15
Texas	65	63	63	60
Virginia	15	15	15	13
West Virginia	26	26	26	24
Total	523	504	501	467

EPA notes that the cost curves presented here differ somewhat from the cost curves presented in the proposal. The NO_X emissions modeled at a $500/ton cost threshold for the final rule are lower than they were at proposal. In addition, the emission reductions they represent from the updated base case are not as pronounced as was found in modeling for the proposed rule. It is worth emphasizing that the lower emission reductions observed at $500/ton in this final rulemaking are due to a lower starting point in updated base case EGU NO_X emission levels (and thus do not reflect higher NO_X emissions remaining after the reductions made at the $500/ton threshold). While the base case 2012 nationwide annual EGU NO_X emissions were approximately 3 million tons in the proposal, they were only 2.1 million tons in the final rule. This approximately 33 percent reduction in base case EGU NO_X emissions in the final rule modeling relative to the proposal is due to a combination of modeling updates, including lower natural gas prices, reduced electricity demand, newly-modeled consent decrees and state rules, and updated NO_X rates to reflect 2009 emissions data. All of these factors resulted in substantially lower base case Transport Rule NO_X emissions in the final rule modeling.

2. Development of SO_2 Cost Curves

As explained in detail below in section VI.D, EPA determined that a single threshold of $500/ton for ozone-season NO_X control in the states covered for the 1997 ozone NAAQS and a single threshold of $500/ton for annual NO_X control in the states covered for the $PM_{2.5}$ NAAQS were appropriate cost thresholds for identifying upwind control under the Transport Rule. With these parameters determined, EPA was able to assess the availability of SO_2 emission reductions from EGUs at various SO_2 cost per ton thresholds with the corresponding NO_X reduction requirements simultaneously represented in the analysis.

This approach of simultaneously modeling cost levels for covered pollutants is different from the approach taken in the proposal. In the proposal, cost curves were developed and examined independently for each pollutant. For example, with the SO_2 cost curves in the proposal, the NO_X cost level was held constant at base case levels as the SO_2 cost threshold was varied from base case levels to $2,400/ton. Commenters noted that this did not accurately reflect a reality where source owners/operators view price signals for all covered pollutants simultaneously and make operation decisions accordingly. For the final rule, EPA included cost thresholds of $500/ton for annual NO_X in $PM_{2.5}$ states and $500/ton for ozone-season NO_X in ozone-season states while examining different SO_2 cost thresholds. This allows EPA to develop final cost curves for air quality analysis and budget determination that reflect EGU operation when faced with the appropriate cost thresholds on all covered pollutants. EPA believes this approach of modeling final cost curves is superior to the methodology used in the proposal because it reflects market signals for each pollutant simultaneously, as would be experienced by states and sources regulated under the Transport Rule.

In this manner, EPA examined several SO_2 cost thresholds of $500, $1,600, $2,300, $2,800, $3,300 and $10,000 per ton. EPA selected these cost thresholds for the final rule's analysis as a representative sampling of points along the SO_2 cost curve thoroughly explored at proposal. Modeling of these cost thresholds provided a spectrum of emission reduction opportunities yielding meaningful differences to consider in total costs and air quality improvements at each threshold. The proposal's more detailed analysis using smaller increments between cost thresholds outlined the general form of the sector's SO_2 emission reduction cost curve and therefore allowed EPA to use larger increments between cost thresholds for the final rule's analysis. Each of the cost thresholds examined for the final rule represents a point where there is a significant change in available controls, emission reductions, or costs and economic impacts. EPA believes analysis of these thresholds illustrate a meaningful progression of costs and air quality impacts that enabled the Agency to determine a proper threshold along this cost curve to identify significant contribution to nonattainment and interference with maintenance for this rulemaking.

The cost thresholds above $500/ton were applied starting in 2014. In all modeling, the 2012 cost per ton threshold was held constant at $500/ton as EPA believes that this cost threshold captures all emission reductions feasible by 2012 (see section VI.B.3 below for more discussion). At the higher cost levels (*e.g.,* $2,800/ton and above), the curve does not include all available reductions as they do not include non-EGU reductions. As described above for NO_X, EPA also observed at proposal that substantial low-cost SO_2 reductions are available from the operation of existing scrubbers that may not otherwise operate in the future without the

Transport Rule in place. Therefore, all of the final SO_2 cost curves assume operation of existing scrubbers in $PM_{2.5}$ states under the Transport Rule. In 2014, approximately 3 million tons of SO_2 reductions can be achieved at the $500/ton cost threshold through operation of existing controls and some fuel switching.

This final cost curve also appropriately reflects the Group 1/Group 2 distinction for states covered for $PM_{2.5}$. As discussed in more detail in section VI.D, EPA identified Group 2 states as those that were linked to states where all nonattainment and maintenance issues had been resolved at $500/ton levels. There is no longer any significant contribution to nonattainment or interference with maintenance by these seven Group 2 states at levels above $500/ton. Therefore, in the final curves, these Group 2 states' cost thresholds were held constant at $500/ton as the higher cost thresholds were applied to the remaining Group 1 states starting in 2014. For example, the modeled emissions at the $2,300 per ton cost threshold shown in Table VI.B–3 below reflect each state's emissions when Group 1 states are subjected to a $2,300 per ton SO_2 constraint and Group 2 states are subjected to a $500/ton SO_2 constraint.

Additional reductions can be achieved at the higher cost thresholds. The cost curves demonstrate that sources begin to build significant additional flue gas desulfurization (FGD) retrofits at an SO_2 cost threshold of $1,600 per ton and additional dry sorbent injection (DSI) retrofits at an SO_2 cost threshold of $2,300 per ton.

With these final cost curves in hand, EPA was able to identify the combined reductions available from upwind contributing states and the downwind state, at different cost-per-ton levels. Additionally, EPA was able to examine the economic impacts of imposing such cost constraints on power sector generation. However, this only constitutes a portion of EPA's multi-factor assessment used to determine the amount of emissions that represent significant contribution to nonattainment and interference with maintenance. As noted in the Transport Rule proposal, EPA's multi-factor assessment considered air quality and cost considerations when identifying cost thresholds (75 FR 45271). The air quality portion of the assessment is described in section VI.C of the final Transport Rule preamble.

3. Amount of Reductions That Could Be Achieved by 2012 and 2014

EPA applied escalating SO_2 cost per ton thresholds for Group 1 states to create the cost curves for 2014 and beyond. For 2012 SO_2, the cost per ton was held constant at $500/ton as the cost thresholds in 2014 and beyond were varied. The advanced pollution controls incentivized by these higher cost-per-ton levels can reasonably be installed by 2014. EPA also considered whether any of these emission reductions could be achieved prior to 2014. For the reasons that follow, EPA concluded that significant reductions could be achieved by 2012 and that it is important to require all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable. SO_2 and NO_X reductions come from operating existing controls, installing combustion controls, fuel switching, and increased dispatch of lower-emitting generation which can be achieved by 2012. In general, compliance mechanisms that do not involve post-combustion control installation are feasible before 2014. For this reason, EPA believes it is appropriate to require these emissions to be removed in 2012, consistent with the Act's requirement that downwind states attain the NAAQS as expeditiously as practicable.

Therefore, all of the cost curves presented below include all feasible 2012 reductions up to a threshold of $500/ton for SO_2 and $500/ton for annual NO_X in states linked to receptors for $PM_{2.5}$, as well as $500/ton for ozone-season NO_X in states linked to receptors for ozone. These cost per ton levels do not precipitate advanced post-combustion control installation in 2012 (as EPA acknowledges that such installations are not feasible by 2012), but they do promote the compliance options outlined above. The higher cost thresholds for SO_2 Group 1 states were only applied starting in 2014. Therefore, the 2012 state level emissions in the "$2,300 per ton threshold" reflect a cost threshold of only $500/ton for all pollutants (the $2,300 per ton value starts in 2014 for Group 1 states' SO_2).

The table below illustrates the change in state level SO_2 emissions as the higher cost per ton thresholds are applied to Group 1 states.

TABLE VI.B–3—2014 SO_2 EMISSIONS FROM FOSSIL-FUEL-FIRED EGUS GREATER THAN 25 MW FOR EACH TRANSPORT RULE STATE AT VARIOUS COSTS PER TON

[Thousand tons] [a]

	State SO_2 group	Base case level	$500	$1,600	$2,300	$2,800	$3,300	$10,000
Alabama	2	417	201	226	213	214	236	190
Georgia	2	170	94	94	95	95	95	98
Illinois	1	138	134	130	124	117	102	36
Indiana	1	711	245	179	161	153	121	69
Iowa	1	127	112	78	75	67	45	13
Kansas	2	70	55	57	61	61	61	45
Kentucky	1	488	161	126	106	103	89	46
Maryland	1	43	32	28	28	26	24	18
Michigan	1	266	206	189	144	105	94	24
Minnesota	2	66	43	45	46	46	46	44
Missouri	1	382	212	173	166	109	84	21
Nebraska	2	72	68	70	70	70	70	66
New Jersey	1	39	7	7	7	7	6	5
New York	1	40	21	20	12	11	10	8
North Carolina	1	120	104	61	58	49	40	30
Ohio	1	832	294	175	137	123	115	65
Pennsylvania	1	507	294	164	112	107	102	75
South Carolina	2	210	93	100	103	104	104	105
Tennessee	1	284	82	63	59	59	59	24

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TABLE VI.B–3—2014 SO_2 EMISSIONS FROM FOSSIL-FUEL-FIRED EGUs GREATER THAN 25 MW FOR EACH TRANSPORT RULE STATE AT VARIOUS COSTS PER TON—Continued

[Thousand tons] [a]

	State SO_2 group	Base case level	$500	$1,600	$2,300	$2,800	$3,300	$10,000
Texas	2	453	281	282	284	281	281	243
Virginia	1	65	59	51	35	33	32	16
West Virginia	1	497	157	122	76	74	72	55
Wisconsin	1	125	51	47	40	38	34	14
Total	....	6,122	3,007	2,487	2,212	2,053	1,919	1,311
Group 1 total	....	4,665	2,172	1,612	1,340	1,180	1,025	520
Group 2 total	....	1,457	835	875	872	872	894	791

[a] **Note**: As described in the preamble language for this section, the escalating cost per ton figures in each column header only apply to Group 1 states in 2014 and each year thereafter. Cost per ton for Group 2 states is held constant at $500/ton for all the costing runs. In some cases, the escalating cost levels in Group 1 states affect emission levels in Group 2 states as some generation shifts between states in response to newly imposed costs.

C. Estimates of Air Quality Impacts (Step 2)

After developing cost curves to show the state-by-state cost-effective emission reductions available, EPA estimates the air quality impacts of these reductions using the air quality assessment tool coupled with full-scale air quality modeling where possible. EPA uses the air quality assessment tool to evaluate the impact on air quality for downwind nonattainment and maintenance receptors from upwind reductions in ''linked'' states. This section describes the development of the air quality assessment tool and summarizes the results of this evaluation.

1. Development of the Air Quality Assessment Tool and Air Quality Modeling Strategy

In response to comments on the methodology used for the proposed rule, EPA made significant improvements to the air quality assessment tool (AQAT) for the final Transport Rule. Furthermore, EPA relied on CAMx to model the air quality response to NO_X reductions and limited AQAT's role (relative to the Transport Rule proposal) to estimating the relative response of sulfate concentrations from SO_2 reductions. EPA did not use AQAT to address NO_X reductions in the final rule analyses. These and other changes to our approach, as described below and in the ''Significant Contribution and State Emission Budgets Final Rule TSD'', address commenter's concerns about the scientific rigor of the design and application of AQAT and commenter's recommendations to rely upon air quality modeling as part of this analysis.

For the final Transport Rule, EPA created an AQAT calibration scenario consisting of full-scale air quality modeling using CAMx of a 2014 control scenario reflecting SO_2 and NO_X emission reductions of similar stringency and from the same geography as the Transport Rule proposal. Modeling of this AQAT calibration scenario reflected all updates made to the air quality modeling platform, as described in the ''Air Quality Modeling Final Rule TSD'' found in the docket for this rulemaking. CAMx modeling of each receptor's response in this control scenario accounts for complex chemical interactions and covariation of these pollutants. Among the important atmospheric chemical interactions accounted for in CAMx is ''nitrate replacement.'' [43] Nitrate replacement occurs when SO_2 emission reductions lead to decreases in ammonium sulfate, which in turn, can result in an increase in ammonium nitrate concentrations. As described below, EPA used the CAMx modeling results for this AQAT calibration scenario together with the modeling for the 2012 base case to characterize the response of ozone, nitrate, and sulfate at each nonattainment and maintenance receptor to the mix of upwind NO_X and SO_2 emission reductions at each cost threshold.

As described in section VI.D, EPA determined that the $500/ton threshold for upwind annual and ozone-season NO_X control is appropriate for the final Transport Rule (although EPA plans to determine in the future whether a higher cost/ton threshold may be warranted for states contributing to nonattainment or maintenance problems with the 1997 ozone air quality standard projected to remain at receptors in two downwind areas [44]). Because this threshold corresponds to the NO_X control strategy modeled in the AQAT calibration scenario described above, EPA is able to rely on this CAMx air quality modeling to assess the response of ozone and nitrate concentrations due to NO_X reductions and does not estimate ozone or nitrate impacts for this final rulemaking using AQAT. Further information on the air quality modeling of this AQAT calibration scenario can be found in the Air Quality Modeling Final Rule TSD and the Significant Contribution and State Emission Budgets Final Rule TSD in the docket for this rulemaking.

In order to estimate 2014 annual and 24-hour $PM_{2.5}$ concentrations, AQAT uses the 2012 annual and seasonal contributions which quantify the contribution of SO_2 emissions in specific upwind states to sulfate concentrations at specific downwind receptors. These contributions are described in section V.D.2 and the Air Quality Modeling Final Rule TSD.

EPA utilizes CAMx modeling of the AQAT calibration scenario, described above, to ''calibrate'' the contribution factors by developing and applying linear sulfate response factors for each downwind receptor. These factors calibrate each receptor's sulfate response to varying levels of upwind SO_2 emissions. These calibration factors are based on the sulfate response modeled by CAMx due to emission changes occurring between the 2012 base case and the 2014 AQAT

[43] Observable indicators of the sensitivity of $PM_{2.5}$ nitrate to emission reductions—Part II: Sensitivity to errors in total ammonia and total nitrate of the CMAQ-predicted non-linear effect of SO_2 emission reductions. R.L. Dennis, P.K. Bhave, and R.W. Pinder. 2008. Atmospheric Environment (42):1287–1300.doi:10.1016/j.atmosenv.2007.10.036.

[44] Houston and Baton Rouge nonattainment areas.

calibration scenario. Calibration factors were constructed for the annual and 24-hour $PM_{2.5}$ AQAT.

To further allow adequate assessment of the seasonal impacts of various levels of upwind SO_2 reductions on each receptor's 24-hour $PM_{2.5}$ concentration using AQAT, EPA developed response factors for sulfate on a quarterly basis to capture important air quality differences between summer and winter emissions and concentrations. This process allowed EPA to estimate the air quality values for each season at each cost threshold, and then estimate the air quality design values.

Finally, EPA's air quality assessment accounts for the impact that this differential response in sulfate by quarter can have on the ordering of 24-hour concentrations when calculating the 98th percentile for the 24-hour standard. AQAT estimates quarterly-specific relative response factors that estimate quarterly-specific proportional change in ammonium sulfate resulting from the SO_2 emission reduction from the 2012 base case scenario to the 2014 cost threshold scenario being assessed. These quarterly relative response factors are then applied to each of the maximum 24-hour $PM_{2.5}$ concentrations for eight days per quarter per year at each receptor from the 2012 base case. This methodology improvement allows EPA to redetermine the 98th percentile day for each year and recalculate average and maximum design values for the 24-hour $PM_{2.5}$ standard.

These improvements for the final rule increase EPA's confidence that the air quality estimates provided by AQAT, now customized for this application, more accurately estimate the results of full-scale air quality modeling of the various levels of upwind SO_2 reductions considered. EPA evaluated the estimates from AQAT using an independent data set, the 2014 base case estimates from CAMx, finding that the results are unbiased with minimal differences. *See* ''Significant Contribution and State Emission Budgets Final Rule TSD'' for more details.

As such, EPA believes the revised AQAT provides an appropriate basis for assessing the air quality portion of the multi-factor methodology to define significant contribution to nonattainment and interference with maintenance.[45]

2. Utilization of AQAT To Evaluate Control Scenarios

For the final Transport Rule, EPA performed air quality analysis for each downwind annual and 24-hour $PM_{2.5}$ receptor with a nonattainment and/or maintenance problem in the 2012 base case. For each receptor, EPA quantified the sulfate reduction and resulting air quality improvement when a group of states consisting of the upwind states that are ''linked'' to the downwind receptor (as explained in section V.D) and the downwind state where the receptor is located, all made the SO_2 emission reductions that EPA identified as available at each cost threshold. EPA assumes reductions at each cost threshold from the linked upwind states as well as the downwind receptor state to assess the shared responsibility of these upwind states to address air quality at the identified receptors. Analysis of each receptor did not assume any emission reductions beyond those included in the 2014 base case from upwind states that are not ''linked'' to that specific downwind receptor (even if the state was ''linked'' to a different receptor and/or otherwise would have made emission reductions beginning in 2012 due to the Transport Rule).

EPA disagrees with comments suggesting that emission reductions, and resulting decreases in contribution, from upwind states that are not ''linked'' to a particular downwind receptor should be accounted for in the 2014 AQAT analysis of that receptor. EPA decided to assume reductions only from linked states when analyzing each receptor because EPA is performing a state-specific analysis to support a determination of the amount of each upwind state's responsibility for air quality problems at the downwind receptors that it significantly affects. If the AQAT analysis were to assume emissions reductions in other non-linked states, the AQAT analysis would then contradict the first step of our two-step approach to defining significant contribution to nonattainment and interference with maintenance. Under EPA's two-step approach, only a state that (1) contributes a threshold amount or more to a particular downwind state receptor's air quality problem, and (2) has emission reductions available at the selected cost threshold can be deemed to have responsibility to reduce its emissions to improve air quality at that downwind receptor. EPA believes that the commenters' suggested approach would not qualify as a state-specific approach for determining upwind state responsibility for downwind air quality problems.

Because EPA is relying on the CAMx estimate of nitrate concentrations from the AQAT calibration scenario, the response in nitrate to NO_X reductions at a cost threshold of $500/ton is present in each SO_2 cost threshold scenario analyzed.

EPA determines the cumulative air quality improvement that can be expected at a particular downwind receptor by multiplying each upwind state's percent SO_2 emission reduction by its calibrated receptor specific sulfate response factor and summing the sulfate, nitrate, and other $PM_{2.5}$ components (also taken from the 2014 CAMx AQAT calibration scenario).

3. Air Quality Assessment Results

The results of EPA's air quality assessment of the cost threshold scenarios focus on air quality metrics including, but not limited to, average air quality improvement at receptors with 2012 base case nonattainment and maintenance exceedances and an evaluation of estimated receptor design values against annual and 24-hour $PM_{2.5}$ standards. *See* ''Significant Contribution and State Emission Budgets Final Rule TSD'' for more details.

In EPA's air quality analysis of each downwind receptor, all air quality improvements are measured relative to the ''AQAT base case.'' This base case reflects AQAT's estimated $PM_{2.5}$ concentrations under base case 2014 SO_2 emissions. The AQAT base case itself is not used for any decision points and only serves as an appropriate starting point for comparison of air quality improvements at SO_2 cost thresholds. EPA ensures internal analytic consistency by comparing all air quality improvements at analyzed SO_2 cost thresholds to the AQAT base case.

Regarding average air quality improvement at exceeding 2012 base case receptors, EPA identified 41 receptors with nonattainment or maintenance problems in the 2012 base

[45] EPA used CAMx to conduct full air quality modeling of the final Transport Rule remedy embodying the emission reductions that EPA first selected on the basis of the multi-factor analysis using AQAT to project air quality impacts from varying levels of emission reductions analyzed. The CAMx results confirmed the relative magnitude and direction of AQAT's estimates of the outcomes for the 2012 base case nonattainment and maintenance receptors analyzed, and the AQAT estimates closely tracked CAMx-modeled concentrations at those receptors under the Transport Rule remedy. The paired AQAT-estimated and CAMx-modeled concentrations were found to be highly correlated with an R^2 value of 0.997. As a result, EPA is confident that AQAT's estimates of impacts on sulfate concentrations at the varying levels of SO_2 emission reductions analyzed provide a technically valid and sound basis for the Agency's selection of the final rule's emission reductions necessary to eliminate (or make meaningful progress toward eliminating) significant contribution and interference with maintenance for the $PM_{2.5}$ NAAQS considered in this rulemaking. Further details on the comparison of CAMx and AQAT results can be found in the Significant Contribution and State Emission Budgets Final Rule TSD.

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case. EPA assessed the cumulative reduction in 24-hour $PM_{2.5}$ maximum design value at each increasing SO_2 cost threshold from the maximum design value from the AQAT base case, and averaged the reduction across the 41 receptors. The results of this assessment indicate diminishing incremental returns to 24-hour $PM_{2.5}$ maximum design value reduction as SO_2 cost threshold levels increase. EPA finds reductions in maximum design value of 4.28 $\mu g/m^3$ at $500; 4.98 $\mu g/m^3$ at $1,600; 5.33 $\mu g/m^3$ at $2,300; 5.46 $\mu g/m^3$ at $2,800; 5.60 $\mu g/m^3$ at $3,300; and 6.08 $\mu g/m^3$ at $10,000. These results are provided in table VI.C–1.

TABLE VI.C–1—AVERAGE 2014 AIR QUALITY IMPROVEMENT AT RECEPTORS WITH 2012 BASE CASE NONATTAINMENT AND MAINTENANCE PROBLEMS

Group 1 state SO_2 cost per ton threshold	Average air quality improvement at exceeding receptors in 2012 base case ($\mu g/m^3$)
$500	4.28
$1,600	4.98
$2,300	5.33
$2,800	5.46
$3,300	5.60
$10,000	6.08

Additionally, EPA evaluated the AQAT estimated 2014 average and maximum design values for these receptors at each cost threshold against the annual and 24-hour $PM_{2.5}$ standards. EPA determined the estimated number of receptors with nonattainment or maintenance problems at $500/ton cost threshold of NO_X and each of the cost threshold scenarios assessed for SO_2. These results are provided in table VI.C–2 in terms of the number of receptors and the number of nonattainment areas containing these receptors.

TABLE VI.C–2—RECEPTORS WITH NONATTAINMENT AND/OR MAINTENANCE EXCEEDANCES OF THE ANNUAL OR 24-HOUR $PM_{2.5}$ NAAQS IN 2014

SO_2 cost threshold	Annual nonattainment		Annual nonattainment or maintenance		24-hour nonattainment		24-hour nonattainment or maintenance		Annual and 24-hour nonattainment and maintenance	
	Receptors	Areas	Receptors	Areas	Receptors	Areas	Receptors	Areas	Receptors	Areas
$500	1	1	1	1	2	2	9	6	9	6
$1,600	1	1	1	1	2	2	8	5	8	5
$2,300	0	0	1	1	1	1	6	4	6	4
$2,800	0	0	1	1	1	1	5	4	5	4
$3,300	0	0	1	1	1	1	5	4	5	4
$10,000	0	0	1	1	1	1	3	3	3	3

In the proposal, EPA evaluated whether the imposition of the rule's upwind emission reduction requirements could cause changes in operation of electric generating units in states not regulated under the proposal. EPA recognized that such changes could lead to increased emissions in those states, potentially affecting whether they would meet or exceed the 1 percent contribution thresholds used to identify linkages between upwind and downwind states. Such shifting of emissions between states may occur because of the interconnected nature of the country's energy system (including both the electricity grid as well as coal and natural gas supplies).

Using updated emissions and air quality information developed for the final rule, EPA's IPM modeling found that of the states not covered in the final rule for $PM_{2.5}$, Arkansas, Colorado, Louisiana, Montana, and Wyoming are all projected to have SO_2 emission increases above 5,000 tons in 2014 with the rule in effect. EPA analysis shows the SO_2 emission increases result from expected shifts to higher sulfur coal in these states. Using AQAT, a state-level assessment of these emission increases relative to the state specific contributions to downwind receptors (where available) indicates that projected increases in the SO_2 emissions would not increase any of these states' contributions to an amount that would meet or exceed the 0.15 $\mu g/m^3$ or 0.35 $\mu g/m^3$ thresholds for annual and 24-hour $PM_{2.5}$, respectively. For this reason, EPA has determined that it is not necessary to include these additional states in the Transport Rule as a result of the effects of the rule itself on SO_2 emissions in uncovered states. *See* ''Significant Contribution and State Emission Budgets Final Rule TSD'' in the docket for this rulemaking for more details.

D. Multi-Factor Analysis and Determination of State Emission Budgets

EPA used the cost, emission, and air quality information described in the previous sections to perform its multi-factor analysis. By looking at different ''cost thresholds''—places where there was a noticeable change on the cost curve because emission reductions occur—and examining the corresponding impact on air quality, EPA identified the amount of emissions that represent significant contribution to nonattainment and interference with maintenance within each state. After quantifying this amount of emissions, EPA established state ''budgets'' which represent the remaining emissions for the state in an average year (step 4).

For states covered by the rule for $PM_{2.5}$, EPA calculated annual NO_X and annual SO_2 budgets. For states covered by the rule for ozone, EPA calculated ozone-season NO_X budgets. This section explains the multi-factor assessment and how EPA used this assessment to determine state-specific budgets.

1. Multi-Factor Analysis (Step 3)

a. Overview

As described in section VI.B, EPA examined how different cost thresholds impacted emissions in states with air quality contributions that meet or exceed specific air quality thresholds, as discussed in section V.D of this preamble. Section VI.C summarizes the estimated air quality impacts in 2014 of these emission levels at downwind receptors, including estimates of their nonattainment and maintenance status (*see* ''Significant Contribution and State Emission Budgets Final Rule TSD'' for more details). From these two steps, EPA evaluated the interaction between upwind emissions at different cost levels and air quality at downwind receptors to identify ''significant cost thresholds.'' These cost thresholds are

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based on air quality considerations (such as the cost at which the air quality assessment analysis projects large numbers of downwind site maintenance and nonattainment problems would be resolved) or cost criteria (such as a cost where large emissions reductions occur because a particular technology is widely implemented at that cost). EPA examined each cost threshold and then used a multi-factor assessment to determine which serve as cost thresholds that eliminate significant contribution to nonattainment and interference with maintenance for upwind states. Air quality considerations in the assessment include, for example, how much air quality improvement in downwind states results from upwind state emission reductions at different levels; whether, considering upwind emission reductions and assumed local (in-state) reductions, the downwind air quality problems would be resolved; and the components of the remaining downwind air quality problem (*e.g.,* whether it is a predominantly local or in-state problem, or whether it still contains a large upwind component).
Cost considerations include, for example, how the cost per ton of emission reduction compares with the cost per ton of existing federal and state rules for the same pollutant; whether the cost per ton is consistent with the cost per ton of technologies already widely deployed (similar to the highly-cost-effective criteria used in both the NO_X SIP Call and CAIR); and what cost increase is required to achieve additional meaningful air quality improvement.

The specific cost per ton thresholds selected as a basis for identifying significant contribution to nonattainment and interference with maintenance in this rulemaking apply only to the determinations made in this rule and do not establish any precedent for future EPA actions under section 110(a)(2)(D)(i)(I) or any other section of the CAA. EPA's selection of specific cost thresholds in the context of this rulemaking relies on current analyses of the cost of available emission reductions, the pattern of interstate linkages for pollution transport, and the downwind air quality impacts specifically related to the 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS, and the 2006 24-hour $PM_{2.5}$ NAAQS. In addition and as explained below, the selection of the threshold for ozone-season NO_X was influenced by the limited scope of this rule. Any or all of these variables used to identify specific cost thresholds are subject to change. Thus, EPA may use different cost thresholds in future actions, even if those actions relate to the same NAAQS addressed in this rule.

b. Cost Thresholds Examined and Selected for Ozone-Season NO_X

In the proposal, EPA examined various cost thresholds for ozone season NO_X and identified a cost threshold with rapidly diminishing returns at $500/ton. EPA observed that moving beyond the $500 cost threshold up to a $2,500 cost threshold would result in only minimal additional ozone season NO_X emission reductions and would likely bypass less expensive non-EGU emission reduction opportunities (75 FR 45281). EPA noted that for greater costs the curves did not include all available reductions as they do not include non-EGU reductions (75 FR 44286). In the proposal, EPA noted the timely promulgation and implementation of this rule is responsive to the Court's remand of CAIR, will accelerate critical air quality improvement, and more effectively address the mandate of CAA section 110(a)(2)(D) to address significant contribution to nonattainment and interference with maintenance as expeditiously as practicable. EPA did not want to risk delaying air quality benefits available from EGU emission reductions, particularly those emission reductions which eliminate significant contribution to nonattainment and interference with maintenance for many receptors, while the Agency conducts additional analysis to support subsequent transport-related rulemakings including coverage of non-EGU sources (75 FR 45285).

EPA received comments suggesting that it consider cost thresholds higher than $500/ton as reductions beyond the proposed $500/ton cost threshold were needed to fully resolve nonattainment and maintenance issues in downwind states analyzed at proposal. Some of these comments suggested EPA should include non-EGUs as they consider the higher cost thresholds, others suggested EPA continue to exclude non-EGU sources in this rulemaking.

In response to those comments that suggested EPA explore higher cost thresholds because nonattainment and maintenance was not fully resolved, EPA first notes that CAA section 110 (a)(2)(D)(i)(I) only requires the elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states. Section 110(a)(2)(D)(i)(I) focuses exclusively on the transport component of nonattainment and maintenance problems. Section 110(a)(2)(D)(i)(I) does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS. As such, the mandate of section 110(a)(2)(D)(i)(I) is not to ensure that reductions in upwind states are sufficient to bring all downwind areas in to attainment, it is simply to ensure that all significant contribution to nonattainment and interference with maintenance is eliminated. Thus, the presence of residual nonattainment or maintenance areas does not, by itself, signify a failure to satisfy the requirements of 110(a)(2)(D)((i)(I).

Furthermore, as noted in section VI.A, EPA is finalizing coverage only for the EGU emission source-sector category in this rulemaking. EPA has not included non-EGU sources in this final rulemaking. EPA remains convinced that timely promulgation and implementation of this rule is responsive to the Court's remand of CAIR.

To the extent that significant contribution is not eliminated for the 1997 ozone NAAQS standard at the $500/ton cost threshold, EPA is not addressing in this rulemaking whether a cost threshold greater than $500/ton is justified for some upwind states and downwind receptors. EPA believes it can best serve these states where concerns persist regarding projected nonattainment or maintenance of the 1997 ozone NAAQS by quickly finalizing this rule and seeking further non-EGU reductions in subsequent rulemakings. Table VI.B–2 illustrates the small amount of EGU reductions available as cost threshold increases above $500/ton. The ozone-season NO_X reductions available in the Transport Rule states between the $500/ton and $1,000/ton cost thresholds amount to less than 3,000 tons. EPA believes that potentially substantial non-EGU ozone-season NO_X reductions become available approaching the $1,000/ton cost threshold. EPA emphasized this in the proposal, noting that the cost curves for ozone season NO_X did not reflect all available reductions as they do not include non-EGU reductions (75 FR 45286). For these reasons, EPA did not consider cost thresholds greater than $500/ton.

EPA did not consider cost thresholds below $500/ton for ozone-season NO_X. $500/ton is a reasonable threshold representing a significant amount of lowest-cost NO_X emission reductions from EGUs, largely accruing from the installation of combustion controls, such as low-NO_X burners, and constitutes a reasonable cost level for operation of existing NO_X controls such as SCRs. EPA believes it would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution). This is increasingly likely to occur at cost thresholds lower than $500/ton. Therefore, EPA did not find cost thresholds lower than $500/ton for ozone-season NO_X to be reasonable for development of the Transport Rule cost curves.

As discussed in section III of this preamble, EPA intends to finalize reconsideration of the March 2008 ozone NAAQS in the summer of 2011 and to expeditiously propose a transport-related action to address any necessary upwind state control responsibilities with respect to that reconsidered NAAQS.

c. Cost Thresholds Examined and Selected for Annual NO_X

Following the assessment of the cost curves in section IV.B and the air quality modeling of the AQAT calibration scenario using CAMx, EPA identified a single cost threshold at $500/ton for annual NO_X. Beyond requiring the year-round operation of existing post-combustion NO_X controls and other reductions modeled at $500/ton threshold, EPA observed a limitation in available low-cost annual NO_X reductions from EGUs. Approximately 7,000 tons of annual NO_X reductions were available from EGUs between the $500/ton and the $1,000/ton cost thresholds (See Table VI.B.–1). Furthermore, above the $500/ton threshold, similar to ozone-season NO_X cost curves, the annual NO_X cost curves do not include all available reductions as they do not include non-EGU reductions. EPA analysis suggests that while NO_X emission reductions lead to reductions in $PM_{2.5}$, SO_2 reductions are generally more cost-effective than NO_X reductions at reducing $PM_{2.5}$ (75 FR 45281). In part, for these reasons, EPA's multi-factor assessment suggested that the $500/ton cost threshold for annual NO_X in concert with the cost thresholds identified for SO_2 were the appropriate cost thresholds for eliminating significant contribution to nonattainment and interference with maintenance. EPA finds in the final Transport Rule that the $500/ton cost threshold for annual NO_X, in concert with the SO_2 cost threshold selected below, successfully eliminates significant contribution to nonattainment and interference with maintenance for the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS in the states covered by this Rule for $PM_{2.5}$.

The reasons for not considering cost thresholds lower than $500/ton for annual NO_X are the same as those identified for not doing so for ozone-season NO_X. In addition to its $PM_{2.5}$ reduction benefits, annual NO_X control at the $500/ton threshold can help to reduce nitrate replacement in the atmosphere. As explained earlier, nitrate replacement happens when SO_2 emissions reductions successfully reduce ammonium sulfate (a component of $PM_{2.5}$) but provoke a $PM_{2.5}$ rebound effect by freeing up additional ammonia to form ammonium nitrate (another component of $PM_{2.5}$).

d. Cost Thresholds Examined and Selected for SO_2

EPA first assessed the downwind air quality impacts of emission reductions modeled at the $500/ton threshold in all states found to be linked to downwind sites for $PM_{2.5}$ transport, as well as in the states hosting those downwind sites. The air quality assessment tool projected that those reductions do not fully resolve nonattainment and maintenance problems with the $PM_{2.5}$ standards for certain areas to which the following states are linked: Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. EPA proceeded to analyze available 2014 emission reductions at higher cost thresholds from these states, collectively referred to as Group 1 states for SO_2 control.

For Group 2 states, the air quality assessment tool projected that the SO_2 reductions at this first cost threshold assessed would resolve the nonattainment and maintenance problems for all of the areas to which the following states are linked: Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina, and Texas. EPA thus finds that these states' significant contribution is eliminated at the $500 per ton level in 2014; they are collectively referred to as Group 2 states for SO_2 control. Because their significant contribution is eliminated at this stringency of control, EPA did not analyze higher cost thresholds for Group 2 states.

The states in Group 1 and Group 2 are rationally grouped considering air quality and cost. EPA determined that it would not be appropriate to assign the same cost threshold to Group 2 and Group 1 states because a significantly lower cost threshold was sufficient to resolve air quality problems at all downwind receptors linked to the Group 2 states. Although states are linked to different sets of downwind receptors, EPA analysis indicated that the cost threshold needed to resolve downwind air quality problems varied only to a limited extent among states within Group 1 and among states within Group 2. It did, however, vary greatly between the Group 1 and Group 2 states. The ruling of the DC Circuit in *Michigan* v. *EPA,* 213 F.3d 663, 679–80 (D.C. Cir. 2000), accepting EPA's prior use of a transport remedy with uniform controls, supports EPA's decision to use a uniform cost threshold for a group of states.

As discussed in section VI.B, the cost threshold for Group 1 states was examined at escalating levels in 2014 (it remained at $500/ton for Group 2 states). EPA examined emissions at SO_2 cost thresholds of $500, $1,600, $2,300, $2,800, $3,300, and $10,000/ton for Group 1 states in 2014. The higher SO_2 marginal costs were only imposed in Transport Rule states starting in 2014, by which time the advanced pollution control retrofits induced at those higher cost thresholds could be installed. (*See* section VI.D.2 for EPA's assessment and decisions regarding SO_2 budget formation in Group 1 states in 2014.)

EPA observed some degree of additional air quality benefit at downwind receptors across all of the cost thresholds examined for SO_2, but significant air quality outcomes were achieved at the $2,300/ton cost threshold. The $2,300/ton threshold is projected to resolve the last remaining nonattainment area for the annual $PM_{2.5}$ standard (Liberty-Clairton),[46] and it also is projected to resolve the nonattainment and maintenance problems with the 24-hour $PM_{2.5}$ standard at 1 monitor in the Detroit area and resolve the maintenance problems in the Cleveland area. There were significant air quality improvements at this level in connection with widespread deployment of pollution control technology, while the cost impacts remained reasonable.

Moving beyond $2,300/ton to the $2,800/ton and $3,300/ton thresholds, EPA projected notably smaller air quality improvements compared to those projected when moving from the $1,600/ton threshold to the $2,300/ton threshold. EPA also projected no ultimate change in the 24-hour $PM_{2.5}$

[46] AQAT results indicated that one receptor in the Liberty-Clairton area continued to have maintenance problems with the annual $PM_{2.5}$ standard. However, final air quality modeling results (described in section VIII.B) indicated that this maintenance problem was resolved for this receptor under the final Transport Rule.

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attainment status of the remaining nonattainment area (Liberty-Clairton) or three remaining maintenance areas (Chicago,[47] Detroit, and Lancaster).[48] At the same time, the total program cost continued to increase by about the same interval at each of these thresholds as it had between the $1,600/ton and $2,300/ton thresholds. EPA thus observed a relatively lower cost-effectiveness of downwind $PM_{2.5}$ control via upwind SO_2 reductions beyond $2,300/ton for the receptors linked to Group 1 states. Table VI.D–1 and Figure VI.D–1 demonstrate this relationship between cost of EGU SO_2 control and downwind $PM_{2.5}$ concentration impacts, showing a sustained diminishing of cost effectiveness beyond the $2,300/ton threshold. The $2,300/ton threshold in this analysis is situated at the ''knee-in-the-curve'' area of cost-effectiveness for addressing downwind $PM_{2.5}$ concentrations with SO_2 reductions, beyond which point the air quality gains per dollar spent on additional reductions are much smaller. This relationship is demonstrative of the economic potency of SO_2 reductions at each cost threshold to address the $PM_{2.5}$ concentrations at linked receptors in this analysis.

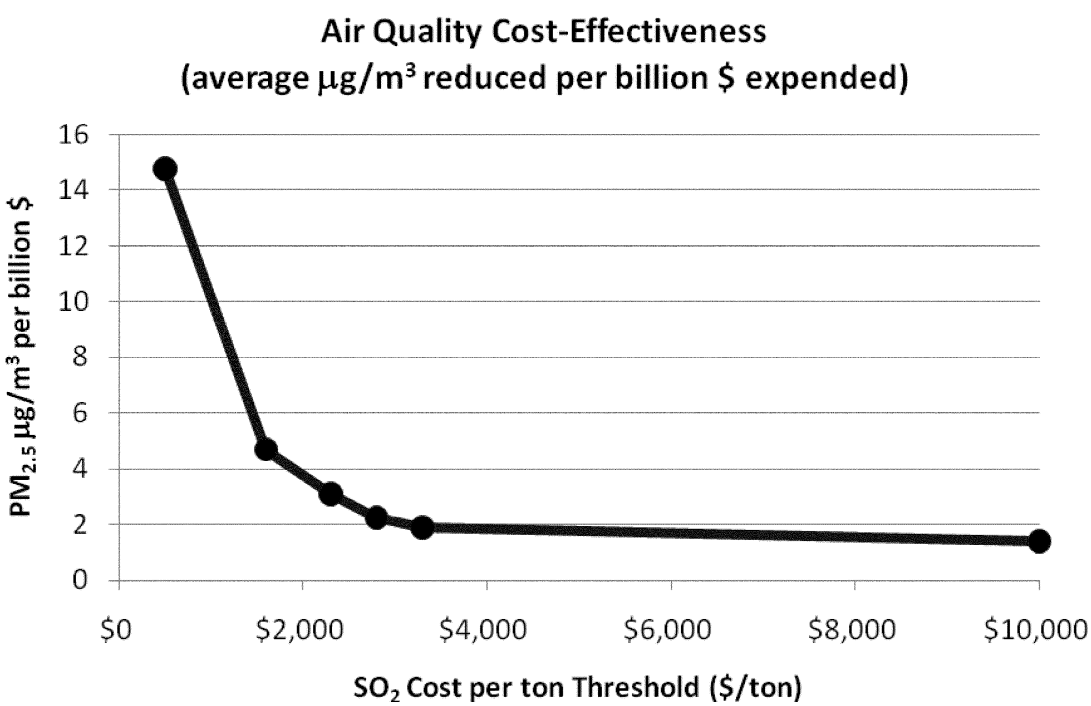
TABLE VI.D–1—COST-EFFECTIVENESS OF GROUP 1 STATE SO_2 REDUCTIONS [a] FOR DOWNWIND $PM_{2.5}$ CONTROL

SO_2 cost threshold	Additional system cost expended (2007$, billions)	Average $PM_{2.5}$ air quality improvement ($\mu g/m^3$) [b]	Air quality cost-effectiveness (average $\mu g/m^3$ reduced per billion $ expended)
$500	0.22	3.27	14.74
$1,600	0.82	3.86	4.70
$2,300	1.35	4.22	3.11
$2,800	1.94	4.37	2.25
$3,300	2.36	4.50	1.91
$10,000	3.61	4.99	1.38

[a] Downwind $PM_{2.5}$ improvement based on SO_2 reductions from states ''linked'' to specific receptors. *See* section VI.C.

[b] Measured as the reduction in maximum design value for the 24-hour $PM_{2.5}$ NAAQS from AQAT base case to each SO_2 threshold for receptors with remaining nonattainment and maintenance exceedances at the $500/ton threshold, averaged across these receptors.

Figure VI.D-1



Furthermore, even at the $10,000/ton cost threshold, AQAT still projects Liberty-Clairton to face maintenance concerns with the annual $PM_{2.5}$ standard and is projected to remain in nonattainment of the 24-hour $PM_{2.5}$ standard, while the Chicago [49] and Lancaster areas are still projected to have residual maintenance problems

[47] This area is not currently designated as nonattainment for the 24-hour $PM_{2.5}$ standard. EPA is portraying the receptors and counties in this area as a single 24-hour maintenance area based on the annual $PM_{2.5}$ nonattainment designation of Chicago-Gary-Lake County, IL-IN.

[48] AQAT results indicated that two receptors in the Detroit area continued to have maintenance problems with the 24-hour $PM_{2.5}$ standard. However, final air quality modeling results (described in section VIII.B) indicated that only one receptor continued to have maintenance problems in this area for this standard under the final Transport Rule.

[49] This area is not currently designated as nonattainment for the 24-hour $PM_{2.5}$ standard. EPA is portraying the receptors and counties in this area as a single 24-hour maintenance area based on the annual $PM_{2.5}$ nonattainment designation of Chicago-Gary-Lake County, IL-IN.

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with the 24-hour $PM_{2.5}$ standard. EPA projected that even total elimination of EGU SO_2 emissions (no matter the cost) would not be able to resolve either nonattainment of the 24-hour $PM_{2.5}$ standard in the Liberty-Clairton area or the residual maintenance concerns with that standard in Lancaster County. EPA thus finds that other $PM_{2.5}$ strategies, including local reductions of other $PM_{2.5}$ precursors, are important to consider for remaining nonattainment and maintenance areas to seek further improvements in $PM_{2.5}$ concentrations.

Considering both air quality and cost, EPA's multi-factor analysis indicated $2,300 per ton as an appropriate cost threshold for SO_2 in the Group 1 states. EPA believes the analyzed cost thresholds lower than $2,300/ton were not appropriate for SO_2 control in the Group 1 states under the Transport Rule for the following reasons:

- Downwind air quality impacts up to the $2,300 threshold are significant. Moving up to $2,300/ton successfully resolves all downwind nonattainment of the annual and 24-hour $PM_{2.5}$ standards except for the Liberty-Clairton receptor in Allegheny county with respect to 24-hour $PM_{2.5}$, which EPA has noted is heavily influenced by a local source of organic carbon (75 FR 45281).
- Upwind emission reductions available up to $2,300/ton are highly cost-effective compared with similar regulations.
- The emission reductions up to this threshold are achievable with widespread deployment of controls that can be installed at power plants by 2014.
- As stated at proposal, EPA finds it reasonable to require a substantial level of control of upwind state emissions that significantly contribute to nonattainment or maintenance problems in another state. The $2,300/ton cost threshold is comparable to EPA's survey of local non-EGU SO_2 reduction opportunities in the $PM_{2.5}$ NAAQS RIA, which range in cost from just above $2,300/ton to over $16,000/ton (2007 $). EPA thus finds it reasonable to seek EGU SO_2 reductions up to $2,300/ton (rather than at a lower cost threshold) in the states linked to receptors with ongoing attainment and maintenance concerns with the $PM_{2.5}$ NAAQS.

EPA believes the analyzed cost thresholds above $2,300/ton were not appropriate for SO_2 control in the Group 1 states under the Transport Rule for the following reasons:

- As noted above, AQAT suggests reductions up to $2,300/ton were able to resolve all projected downwind nonattainment of the annual and 24-hour $PM_{2.5}$ NAAQS, with the sole exception of projected nonattainment of the 24-hour $PM_{2.5}$ standard at a receptor in Liberty-Clairton. It is well-established that, in addition to being impacted by regional sources, the Liberty-Clairton area is significantly affected by local emissions from a sizable coke production facility and other nearby sources, leading to high concentrations of organic carbon in this area.[50] EPA finds that the remaining $PM_{2.5}$ nonattainment problem is predominantly local and therefore does not believe that it would be appropriate to establish a higher cost threshold solely on the basis of this projected ongoing nonattainment of the 24-hour $PM_{2.5}$ standard at the Liberty-Clairton receptor.
- Approximately 70 percent of base case SO_2 emissions from Group 1 states were eliminated at the $2,300/ton cost threshold, leaving a decreasing amount of emission reductions available at each increased cost threshold beyond $2,300/ton.
- Additional EGU SO_2 reductions available from EGUs beyond the $2,300/ton threshold level realize significantly less improvement in downwind $PM_{2.5}$ concentrations per dollar spent to impact receptors linked to Group 1 states. In other words, the cost-effectiveness of controlling EGU emissions in Group 1 states to improve downwind $PM_{2.5}$ concentrations at the linked receptors is notably diminished beyond the $2,300/ton threshold in this analysis. *See* Figure VI.D–1.
- EGUs are by far the largest source category for SO_2 emissions. This analysis shows that reductions of EGU SO_2 emissions up to the $2,300/ton cost threshold were significantly more cost-effective for improving downwind $PM_{2.5}$ concentrations than further such reductions (beyond the $2,300/ton cost threshold) would be to address the remaining $PM_{2.5}$ maintenance concerns. EPA's analysis also shows that these maintenance concerns cannot be fully resolved even with complete elimination of all remaining EGU SO_2 emissions, no matter the cost. EPA finds that other $PM_{2.5}$ precursor emission reductions, particularly those from local sources will be critical for states in these remaining areas to consider for controlling $PM_{2.5}$ concentrations with respect to maintenance of the 2006 24-hour $PM_{2.5}$ NAAQS.

In summary, the appropriate cost thresholds for each state were identified through the multi-factor assessment. This assessment included both cost and air quality considerations. As explained above, the ozone-season NO_X threshold was determined to be $500/ton for all states required to reduce ozone-season NO_X, with residual nonattainment and maintenance concerns to be addressed in a future rulemaking addressing a broader set of source categories for additional cost-effective reductions. For $PM_{2.5}$, the appropriate cost threshold for each state was determined to be either the level at which nonattainment and maintenance issues were completely resolved in downwind states to which the state is linked, the level where remaining nonattainment and maintenance issues are primarily local, or where we found greatly diminished improvements in air quality occurring if EPA moved further up the cost curve. This assessment yielded a cost threshold of $2,300/ton on SO_2 for Group 1 states starting in 2014 ($500/ton in 2012), a cost threshold of $500/ton on SO_2 for Group 2 states, and a cost threshold of $500/ton on annual NO_X for all states required to reduce emissions for purposes of the annual or 24-hour $PM_{2.5}$ NAAQS in this rule.

As explained above, none of these specific cost thresholds establish any precedent for the cost per ton stringency of reductions EPA may require in future transport-related rulemakings; these specific cost thresholds are based on current analyses of air quality and cost of emission reductions with respect to the NAAQS considered in this rulemaking and thus would not be relevant to future rulemakings (which would consider updated information) or rulemakings with respect to different NAAQS. In particular, EPA acknowledges that additional action EPA will require in a subsequent rulemaking to address significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS (once reconsideration is finalized) is very likely to require a higher cost per ton stringency of ozone-season NO_X control applied to a broader set of source categories from upwind states than found to be appropriate for this rulemaking.

2. State Emission Budgets (Step 4)

a. Budget Methodology

EPA used the multi-factor assessment to identify, for each state, the cost threshold that should be used to quantify that state's significant contribution. As described above, in the context of this rulemaking EPA identified a cost threshold of $500/ton for ozone-season NO_X control for all states required to reduce ozone-season

[50] *http://www.epa.gov/pmdesignations/2006standards/final/TSD/tsd_4.0_4.3_4.3.3_r03_PA_2.pdf.*

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NO_X emissions for purposes of the 1997 ozone NAAQS in this rule. EPA also identified a cost threshold of $500/ton for annual NO_X control for all states required to reduce annual NO_X emissions for purposes of the annual or 24-hour $PM_{2.5}$ NAAQS in this rule. Finally, EPA identified a cost threshold of $500/ton of SO_2 starting in 2012 for all states required to reduce SO_2 emissions for purposes of the annual or 24-hour $PM_{2.5}$ NAAQS in this rule, and $2,300/ton for the Group 1 states starting in 2014.

EPA used these cost thresholds from the multi-factor analysis to quantify each state's emissions that significantly contribute to nonattainment or interfere with maintenance downwind. For example, for a Group 1 state, EPA modeling of the cost threshold conveys emission reductions available in each covered state from operation of existing pollution controls as well as all emission reductions available at cost thresholds of $500/ton for annual NO_X in 2012 and 2014, $500/ton for SO_2 in 2012, and $2,300/ton for SO_2 in 2014. The total SO_2 and NO_X projected at these cost levels in that state in those years represents that state's emissions once significant contribution to nonattainment or interference with maintenance downwind for the relevant $PM_{2.5}$ NAAQS has been eliminated.

TABLE VI.D–2—EXAMPLE OF EMISSION REDUCTIONS AND BUDGET FORMATION IN PENNSYLVANIA FOR ANNUAL SO_2 AND NO_X[a]

		Final cost threshold	Base case emissions (1,000 tons)	Remaining emissions at cost thresholds (1,000 tons)	Emissions eliminated (1,000 tons)
A	B	C	D	E	F
2012	SO_2	$500	493	279	215
	NO_X	500	129	120	9
2014	SO_2	2,300	507	112	395
	NO_X	500	132	119	13

[a] **Note:** In this table, emissions are shown for fossil-fuel-fired EGUs > 25 MW (*i.e.*, those units likely covered by the Transport Rule). Table VI.D.2 illustrates how budgets are derived from the elimination of significant contribution for the state of Pennsylvania. Column C illustrates the cost thresholds applied in the costing run that was ultimately identified as the final cost threshold in the multi-factor analysis. Column D shows the base case emissions for the identified pollutant in the identified time period. Column E shows the emission levels that result when the cost thresholds identified in column C are applied. Because this is the cost threshold identified through the multi-factor analysis and the point where all significant contribution to nonattainment and interference with maintenance has been addressed for the $PM_{2.5}$ NAAQS—state budgets are based on these emission levels. The final column illustrates the emission reductions for the state in an average year (before accounting for variability).

EPA's modeling of a state's SO_2 and annual NO_X emission levels (from fossil-fired EGUs > 25 MW) at the relevant cost thresholds in each state reflect that state's emissions from covered sources after the removal of significant contribution to nonattainment and interference with maintenance of the $PM_{2.5}$ NAAQS considered in this rulemaking. As these state emission levels reflect the removal of significant contribution and interference with maintenance, they are reasonable levels on which to determine state budgets. Consequently, EPA based state budget levels on the state level emissions that remained at the cost threshold. Each state's budget corresponds to its emission level following the elimination of significant contribution to nonattainment and interference with maintenance in an average year (before taking year-to-year variability into account, as discussed in section VI.E below). Therefore, the implementation and realization of these budgeted emission levels leads to the elimination of significant contribution to nonattainment and interference with maintenance and EPA meets the statutory mandate of section 110(a)(2)(D)(i)(I) with respect to the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS.

EPA's establishment of state budgets for ozone-season NO_X control follow the same methodology as described above for SO_2 and annual NO_X. Implementation of these ozone-season NO_X budgets reflects the elimination of significant contribution to nonattainment and interference with maintenance of the 1997 ozone NAAQS for 15 states, whereas 11 other states' ozone-season NO_X budgets reflect meaningful progress toward (but may not reflect full completion of) this elimination under the mandate of section 110(a)(2)(D)(i)(I). *See* section III for lists of states.

This approach to basing budgets on projected state level emissions used in the multi-factor analysis is identical to the approach used in the proposal for determining 2014 SO_2 budgets for Group 1 states. EPA is extending this approach more broadly in the final Transport Rule to create state budgets for ozone-season NO_X, annual NO_X, and SO_2 in all relevant states in both 2012 and 2014. In the proposal EPA used a more complex approach based on a comparison of historic and projected unit-level emissions (further adjusted for operation of existing controls) in each state to create 2012 state budgets for ozone-season NO_X, annual NO_X, and Group 2 SO_2. At the time of proposal, EPA believed that historic 2009 emissions data were in some cases more representative of expected emissions in 2012 than pure modeling projections made at the time (75 FR 45290).

However, following the proposal EPA has made significant updates to the IPM model for projecting EGU emissions, including specifically the adoption of 2009 historic data into its modeling parameters directly. EPA also received substantial public input following the proposal on the model's assumptions and representation of individual units, which allowed EPA to improve its 2012 and 2014 emission projections for states under the cost thresholds considered. These modeling updates diminish the concerns EPA expressed at proposal that 2009 historic data may have offered for some states a better proxy for 2012 emissions than model projections, particularly now that EPA is incorporating 2009 data directly in its updated modeling projections. Given these updates to the model in response to public comment, EPA believes it is more appropriate for the final rule to use a consistent approach based on projected state level emissions for all state budgets, as was done for Group 1 SO_2 budgets in 2014 at proposal. EPA received significant comment supporting the use of the model to

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project state-level emissions for creating budgets in this manner. EPA also received comments that criticized the proposal's methodology for 2012 budgets for lack of transparency, unnecessary complexity, and inconsistency with the state-level emission projections used in the air quality modeling. EPA's decision for the final Transport Rule to consistently apply across all pollutants the budget methodology originally used for Group 1 SO_2 budgets in 2014 addresses those concerns.

This budget methodology for the final rule uses projected state-level emissions in 2012 and 2014 to set emission budgets for those years on relevant pollutants for that state to control under the Transport Rule. EPA's modeling projects that some states have 2014 emissions that are lower than their 2012 projected emissions even as the same cost threshold (*e.g.,* $500/ton) is applied in both years. This occurs in the annual NO_X, ozone-season NO_X, and Group 2 SO_2 program. As such, EPA's application of this budgeting methodology results in a tightening of budgets in states whose projected emissions of that budgeted pollutant decline from 2012 to 2014 as the cost threshold is held constant.

There are two primary variables that explain the decrease in emissions for some states between 2012 and 2014 as the cost threshold remains constant over both time periods. First, even though the cost threshold is constant between 2012 and 2014 for the programs noted above, the cost threshold for SO_2 Group 1 increases in 2014. This higher cost threshold for Group 1 SO_2 results in obvious reductions in SO_2 emissions in the Group 1 states, but also may lower the cost of certain related NO_X reductions in those states as well such that they become newly available within the $500/ton threshold. For example, if a state increases natural gas generation in response to the higher SO_2 cost threshold, such action also yields additional annual and ozone-season NO_X emission reductions that are cost-effective at the $500/ton NO_X threshold. Where the cost curve modeling shows such additional cost-effective NO_X reductions in tandem with SO_2 control, EPA is therefore reducing those states' 2014 annual NO_X and ozone-season NO_X budgets accordingly, so that those budgets accurately reflect remaining emissions from covered sources in those states after the elimination of all emissions that can be reduced up to the relevant cost thresholds (*e.g.,* $500/ton).

Second, some of these additional reductions are driven by non-Transport Rule variables. These are reductions that occur due to state rules, consent decrees, and other planned changes in generation patterns that occur after 2012, but during or prior to 2014. For example, EPA modeling reflects emission reduction requirements under provisions of a Georgia state rule that go into effect after 2012 but before 2014. These requirements involve the installation and operation of specific advanced pollution controls. These source-specific requirements under a legal authority unrelated to the Transport Rule result in sharp reductions in Georgia's baseline emission projections between 2012 and 2014. Even though the cost threshold for NO_X and for SO_2 in Georgia is $500/ton in both 2012 and 2014, EPA believes it is important to establish separate NO_X and SO_2 budgets that accurately reflect the emissions remaining in Georgia (and other states experiencing similar reductions) after the elimination of emissions that can be reduced up to the Transport Rule remedy's cost thresholds (*e.g.,* $500/ton) (see Table VI.D.3). It illustrates a notable decrease between the 2012 and 2014 state budgets for NO_X and SO_2 in Georgia that is largely driven by state rule requirements. If EPA did not adjust 2014 budgets to account for other emission reductions that would occur even in the baseline, other sources within the state would be allowed to increase their emissions under the unadjusted Transport Rule budgets to offset the emission reductions planned under other requirements such as state rules. Therefore, to prevent the Transport Rule from allowing such offsetting of emission reductions already expected to occur between 2012 and 2014, EPA is establishing separate budgets for 2012 and 2014 in the final Transport Rule to capture emission reductions in each state that would occur for non-Transport Rule-related reasons (*i.e.,* in the base case) during that time.

EPA's modeling also projects that other states would slightly increase emissions from 2012 to 2014 even at the same cost threshold, such as $500/ton. There are two primary variables that explain the increase in emissions for these states between 2012 and 2014. These increases are generally small in magnitude. For annual and ozone season NO_X, they occur as a byproduct of small changes in dispatch related to changes in non-Transport Rule factors (*e.g.,* higher demand in 2014). For SO_2, they primarily occur in Group 2 states and, in addition to the reasons given above, are influenced by some generation shifting from Group 1 to Group 2 states as the Group 1 states begin to face a higher cost threshold in 2014. EPA believes that allowing for such emission growth in covered states beyond 2012 would be inconsistent with the Transport Rule's identification and elimination of significant contribution to nonattainment and interference with maintenance beginning in 2012. Therefore, for any covered state whose emissions of a relevant pollutant are projected to increase from 2012 to 2014 under the relevant cost thresholds selected in the multi-factor analysis described above, EPA is finalizing that state's 2014 emission budget to maintain the same level of the 2012 emission budget, thereby disallowing such an emission increase that is inconsistent with the 110(a)(2)(D)(i)(I) mandate. Tables VI.D–3 and VI.D–4 below list state emission budgets.[51]

TABLE VI.D–3—SO_2 AND ANNUAL NO_X STATE EMISSION BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY *

[Tons]

	Group	SO_2		NO_X	
		2012–2013	2014 and beyond	2012–2013	2014 and beyond
Alabama	2	216,033	213,258	72,691	71,962
Georgia	2	158,527	95,231	62,010	40,540

[51] These budgets include minor technical corrections to SO_2 budgets in three states (KY, MI, and NY) that were made after the impact analyses for the final rule were conducted. EPA conducted sensitivity analysis confirming that these differences do not meaningfully alter any of the Agency's findings or conclusions based on the projected cost, benefit, and air quality impacts presented for the final Transport Rule. The results of this sensitivity analysis are presented in Appendix F in the final Transport Rule RIA.

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TABLE VI.D–3—SO_2 AND ANNUAL NO_X STATE EMISSION BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY *—Continued

[Tons]

	Group	SO_2		NO_X	
		2012–2013	2014 and beyond	2012–2013	2014 and beyond
Illinois	1	234,889	124,123	47,872	47,872
Indiana	1	285,424	161,111	109,726	108,424
Iowa	1	107,085	75,184	38,335	37,498
Kansas	2	41,528	41,528	30,714	25,560
Kentucky	1	232,662	106,284	85,086	77,238
Maryland	1	30,120	28,203	16,633	16,574
Michigan	1	229,303	143,995	60,193	57,812
Minnesota	2	41,981	41,981	29,572	29,572
Missouri	1	207,466	165,941	52,374	48,717
Nebraska	2	65,052	65,052	26,440	26,440
New Jersey	1	5,574	5,574	7,266	7,266
New York	1	27,325	18,585	17,543	17,543
North Carolina	1	136,881	57,620	50,587	41,553
Ohio	1	310,230	137,077	92,703	87,493
Pennsylvania	1	278,651	112,021	119,986	119,194
South Carolina	2	88,620	88,620	32,498	32,498
Tennessee	1	148,150	58,833	35,703	19,337
Texas	2	243,954	243,954	133,595	133,595
Virginia	1	70,820	35,057	33,242	33,242
West Virginia	1	146,174	75,668	59,472	54,582
Wisconsin	1	79,480	40,126	31,628	30,398
Grand Total		3,385,929	2,135,026	1,245,869	1,164,910
Group 1 Total		2,530,234	1,345,402	NA	NA
Group 2 Total		855,695	789,624	NA	NA

Note: These state emission budgets apply to emissions from electric generating units covered by the Transport Rule Program. Group 1/Group 2 designations are only relevant for SO_2 emissions budgets.
* The impact of variability on budgets is discussed in section VI.E.

The District of Columbia is not covered by the final Transport Rule. As discussed in section V.D of this preamble and as done for the Transport Rule proposal, EPA combined contributions projected in the air quality modeling from Maryland and the District of Columbia to determine whether those jurisdictions collectively contribute to any downwind nonattainment or maintenance receptor in amounts equal to or greater than the 1 percent thresholds. This modeling confirmed that the combined contributions exceed the air quality threshold at downwind receptors for the ozone, annual $PM_{2.5}$, and 24-hour $PM_{2.5}$ NAAQS considered. Both Maryland and the District of Columbia are therefore linked to these receptors.[52] However, the District of Columbia is not included in the Transport Rule because, in the second step of EPA's significant contribution analysis, we concluded that there are no emission reductions available from EGUs in the District of Columbia at the cost thresholds deemed sufficient to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS considered at the linked receptors. At the time of this rulemaking, EPA finds only one facility with units meeting the Transport Rule applicability requirements in the District of Columbia. EPA's projections do not show any generation from this facility to be economic under any scenario analyzed (including the base case), and the facility's owners have also announced plans to retire its units in early 2012.[53] Therefore, this unit is projected to have zero emissions in 2012. As such, the total SO_2 and NO_X emissions in the District of Columbia for EGUs that meet the Transport Rule applicability requirements is also projected to be zero. It follows therefore, that EPA did not identify any emission reductions available at any of the cost thresholds considered in the final rule's multi-factor analysis to identify significant contribution to nonattainment and interference with maintenance. For this reason, EPA concludes that no additional limits or reductions are necessary, at this time, in the District of Columbia to satisfy the requirements of section 110(a)(2)(D)(i)(I) with respect to the 1997 ozone, the 1997 $PM_{2.5}$ and the 2006 $PM_{2.5}$ NAAQS. EPA is therefore neither establishing budgets nor finalizing any FIPs for the District of Columbia in this rule.

[52] It is important to note that Maryland's modeled contributions in isolation were greater than the 1 percent threshold for all three of the NAAQS considered at all of the same receptors for which Maryland and DC were ''linked,'' and therefore EPA would have considered Maryland ''linked'' to the same set of downwind receptors even if the Agency had treated Maryland's contributions and the District of Columbia's contributions separately.

[53] The future retirement status of this D.C. facility was also supported by its inclusion on PJM's future deactivation list. PJM further suggested that reliability issues related to their retirement are expected to be resolved by next year in time for its planned retirement date. (*See* PJM pending deactivation request in TR Docket.)

TABLE VI.D–4—OZONE SEASON NO_X STATE EMISSION BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY *

[Tons]

	2012–2013	2014 and beyond
Alabama	31,746	31,499
Arkansas	15,037	15,037
Florida	27,825	27,825
Georgia	27,944	18,279
Illinois	21,208	21,208

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TABLE VI.D–4—OZONE SEASON NO_X STATE EMISSION BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY *—Continued

[Tons]

	2012–2013	2014 and beyond
Indiana	46,876	46,175
Kentucky	36,167	32,674
Louisiana	13,432	13,432
Maryland	7,179	7,179
Mississippi	10,160	10,160
New Jersey	3,382	3,382
New York	8,331	8,331
North Carolina	22,168	18,455
Ohio	40,063	37,792
Pennsylvania	52,201	51,912
South Carolina	13,909	13,909
Tennessee	14,908	8,016
Texas	63,043	63,043
Virginia	14,452	14,452
West Virginia	25,283	23,291
Total	495,314	466,051

Note: These state emission budgets apply to emissions from electric generating units covered by the Transport Rule Program. Group 1/Group 2 designations are only relevant for SO_2 emissions budgets.

* The impact of variability on budgets is discussed in section VI.E.

EPA notes that the NO_X budgets for five states linked to downwind ozone receptors in the final Transport Rule are equal to their projected 2012 base case emissions. The five states are Arkansas, Indiana, Louisiana, Maryland, and Mississippi. These states are among those found to meet or exceed the 1 percent contribution threshold for the 1997 ozone NAAQS at downwind receptors and are thus ''linked'' to downwind receptors. EPA therefore evaluates, in the second step of its significant contribution analysis, what emission limits are necessary to ensure that all emissions that constitute the state's significant contribution to nonattainment and interference with maintenance are prohibited. As explained above, EPA decided to require from all such states all reductions available at the $500/ton cost threshold. The five states identified above do not appear to show EGU ozone-season NO_X reductions at the $500/ton cost threshold relative to the 2012 base case projections (which do not take into account reductions to be made in other states as a result of this rule). Therefore, EPA conducted further analysis to evaluate whether such reductions were available in these states and whether emission limits are necessary to prohibit these states from significantly contributing to downwind nonattainment or interfering with maintenance of the 1997 ozone NAAQS in other states. (*See* the docket to this rulemaking for the IPM run titled TR_uncontrolled_ozone_states_Final.'')

Specifically, EPA projected those states' ozone-season NO_X emissions if all other linked states (but not these five states) were to make all available reductions at the $500/ton threshold. That analysis revealed that if emission limits were not established for these five states, ozone-season NO_X emissions in each of the states would increase (beyond the 2012 base case emission projections), due to interstate shifts in electricity generation that cause ''emissions leakage'' in uncovered states. These increases would result in each state's emissions being above the level associated with the prohibition of all emissions that can be eliminated at the $500/ton threshold. EPA thus determined that it is necessary to establish emission limits for these states at the $500/ton level. These limits, although equal to the state's 2012 projected base case emissions, are necessary to prohibit all emissions that can be controlled at the $500/ton cost threshold. In other words, the significant contribution to nonattainment and interference with maintenance addressed by the ozone FIPs for these states is the difference between these states' projected emissions if they were not covered under the Transport Rule (but other states were), and their emissions after all emissions that can be eliminated at $500/ton are prohibited.

In addition, EPA notes that four of these five states (Arkansas, Indiana, Louisiana, and Mississippi) are linked to receptors in either the Houston or Baton Rouge areas, which are projected to continue facing nonattainment or maintenance concerns with the 1997 ozone NAAQS, respectively. To allow these states to increase emissions above base case projections would erode the measurable progress toward eliminating significant contribution to nonattainment and interference with maintenance secured by achieving ozone-season NO_X reductions in the other states linked to these receptors. Furthermore, as discussed in section III, EPA may require additional reductions in these states to fully address significant contribution to nonattainment and interference with maintenance with respect to the 1997 ozone NAAQS in a future rulemaking to be proposed after finalizing reconsideration of the 2008 ozone NAAQS.

b. Relationship of Group 1 and Group 2 States for SO_2 Control

In the Proposal, EPA chose not to allow sources in Group 1 states to use Group 2 SO_2 allowances for compliance, and likewise not to allow sources in Group 2 states to use Group 1 SO_2 allowances for compliance at any time. The preamble clearly states, ''With regard to interstate trading, the two SO_2 stringency tiers would lead to two exclusive SO_2 trading groups. That is, states in SO_2 Group 1 could not trade with states in SO_2 Group 2'' (75 FR 45216). No such distinction or limitation exists for NO_X allowance trading.

EPA received significant public comment both in support and opposition to the two distinct SO_2 trading programs. Those in opposition noted that the variability limits imposed at the state level made the compliance restrictions between the two groups unnecessary. Commenters also noted that it may unfairly penalize sources that are part of the same airshed, but are on opposite sides of a state boundary. Those in favor of the separate SO_2 compliance programs noted that it would reduce the probability of a state exceeding its variability limit. Allowing the use of Group 1 or Group 2 allowances for compliance between the two SO_2 programs would potentially encourage Group 1 states to purchase allowances instead of making reductions necessary to eliminate significant contribution. Group 1 states are states that need continued reductions (beyond the $500/ton threshold) to eliminate their significant contribution to nonattainment and interference with maintenance. Group 2 states have already eliminated their significant contribution to nonattainment and interference with maintenance at the $500/threshold. So to allow Group 1 or Group 2 allowances to be used interchangeably for compliance between the two SO_2 groups would be to allow the shifting of reductions from areas where they are needed to eliminate significant contribution to nonattainment and interference with maintenance to areas where they are not needed to eliminate the prohibited emissions. EPA also agrees that allowing for trading between the two groups in the remedy finalized in this action would increase risk of a state exceeding its variability limit. For these reasons, EPA is finalizing this rulemaking with the same prohibition on SO_2 trading between Group 1 and Group 2 states that was defined in the proposal. Further, EPA clarifies that while trading of allowances (*i.e.,*

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buying, selling, and banking) is allowed without restriction, it is specifically the surrender of SO_2 allowances for compliance that is limited. As mentioned earlier, a source in a Group 1 state can only use SO_2 allowances allocated to Group 1 states for compliance with the SO_2 trading program. Likewise, a source in a Group 2 state can only use SO_2 allowances allocated to Group 2 states for compliance with the SO_2 trading program.

c. Ozone-Season Budgets

EPA established the ozone-season NO_X budgets in a similar manner to the annual NO_X and SO_2 budgets by using the state level emissions from the cost threshold that reflected the removal of significant contribution to nonattainment and interference with maintenance. Ozone-season budgets were based on the state level emissions from fossil-fuel-fired units greater than 25 MW observed at this cost threshold. As described in section VI.B, all cost thresholds examined reflected the final Transport Rule geography and the marginal costs were applied accordingly. Therefore, for an ozone-only state like Florida, the state level emissions would only reflect an ozone-season cost threshold of $500/ton in the final cost curves for 2012 and 2014. For a state subject to both annual and ozone-season programs, the marginal cost curves would reflect a $500/ton NO_X cost year round, a $500/ton SO_2 cost in 2012 and the $2,300/ton SO_2 cost starting in 2014 if a Group 1 state.

(1) Length of Ozone Season

(a) Proposed Rule. For purposes of determining ozone-season budgets in the proposed rule, EPA defined the ozone season based on a 5 month period (May 1 through September 30). This 5 month ozone season was consistent with the approach taken by the OTAG, the NO_X SIP Call, and CAIR. EPA requested comment on whether EPA should base final rule budgets on a longer season, such as March through October.

(b) Public Comments. Several commenters supported continuing with the May through September time period. One commenter supported continuing with this time period, but argued that EPA should consider lengthening the ozone season for future efforts. One commenter questioned the concept of ozone season budgets and recommended EPA focus on sources with greater emissions on high ozone days.

(c) Final rule. For the final rule, EPA has retained the approach in the proposed rule, as commenters broadly supported the proposal's ozone-season duration and ozone-season NO_X limitations. Notably, many Transport Rule states covered for $PM_{2.5}$ reductions will have sources with annual NO_X controls that are likely to keep operating year round to address $PM_{2.5}$ and ozone. EPA believes that experience from ozone-season NO_X trading has consistently shown that the emission measures taken to comply with ozone-season budgets provide emission reductions throughout the ozone-season, including the highest ozone days. (*See* NO_X Budget Trading Program and CAIR Program progress reports in the docket to this rulemaking or at *http://www.epa.gov/airmarkets/progress/nbp08.html* and *http://www.epa.gov/airmarkets/progress/CAIR_09/CAIR09.html.*) However, EPA believes that there is merit in future Agency actions addressing ozone transport in considering strategies to target high ozone days more specifically.

d. Summary of Cost Thresholds and Final Budgets for $PM_{2.5}$ and Ozone

Summary of methodology. In summary, EPA determined that SO_2 emissions that could be reduced for $2,300/ton in 2014 should be considered a state's significant contribution to nonattainment and interference with maintenance, unless EPA determined that a lesser reduction would fully resolve the nonattainment and/or maintenance problem for all the downwind receptors to which a particular state might be linked. For these Group 2 states EPA is determining that a lesser reduction of SO_2, based on the amount of SO_2 reductions that can be reasonably achieved by 2012 is appropriate. This level is defined by the reductions observed in the $500/ton cost threshold. EPA also determined that all states linked to downwind $PM_{2.5}$ nonattainment and maintenance problems should be required to achieve those emission reductions that can be reasonably achieved by 2012. Finally, EPA determined that all states linked to downwind $PM_{2.5}$ nonattainment and maintenance problems should, by 2012, remove all NO_X emissions that can be reduced for $500/ton and run all existing controls in 2012.

For ozone-season NO_X, EPA determined that all states linked to downwind ozone and nonattainment and maintenance problems should be required to achieve those ozone-season emission reductions associated with a cost threshold of $500 per ton. Additionally, EPA examined final 2012 and 2014 budgets based on state level emissions at $500 cost threshold.

The budget formation methodology finalized in this action responds to concerns about state budgets expressed by commenters on the Transport Rule proposal. EPA requested comment on the four step approach used to determine significant contribution and determine budgets in the proposal. Some commenters noted that the state level emissions from the cost thresholds used to determine significant contribution to nonattainment and interference with maintenance did not match the state level emissions allowed by the final budgets. The concern was that the state level emissions that reflected the elimination of significant contribution in the AQAT analysis, in particular for NO_X, were less than the emissions allowed by the final budgets. The result would be an implementation that did not quite fully eliminate the significant contribution to nonattainment and interference with maintenance defined in the rule. The proposed budgets not matching the levels reflected in the proposed costing runs were an artifact of the budget formation process that relied on a combination of historic and projected data. While EPA noted this process resulted in state budgets that ''reflected'' EGU emissions at $500/ton, it was not always consistent with the EGU emissions at $500/ton in the costing runs as the commenters noted. By using the cost curves to determine both significant contribution to nonattainment and interference with maintenance—and state budgets—in the final rule, EPA addresses the commenter's concerns about any inconsistency between the two in the proposal.

Some commenters expressed concern that the Transport Rule would result in state budgets that were in some cases higher than those established in CAIR. Commenters suggested that this would be inconsistent with requirements or the spirit of certain CAA provisions aimed at preventing backsliding, *i.e.,* sections 110(l), 172(e), and 193. However, the DC Court of Appeals rejected the state budgets in CAIR as arbitrary and capricious and not consistent with CAA section 110(a)(2)(D)(i)(I) (North Carolina, 531 F.3d 918 and 921) and remanded CAIR to EPA to promulgate a new rule replacing CAIR and consistent with the Court's decision (North Carolina, 550 F.3d 1178). As discussed elsewhere in this section, on remand EPA developed new, final state budgets that address the Court's concerns and meet section 110(a)(2)(D)(i)(I) requirements.

Although some state budgets under the final rule are higher than those

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under CAIR, this does not violate either the letter or the spirit of CAA provisions aimed at backsliding. In particular, CAA section 110(l) provides that the Administrator may not approve a plan revision that would ''interfere with any * * * applicable requirement'' of the CAA. 42 U.S.C. 7410(l). Because the Court reversed and remanded CAIR with instructions to ''remedy'' the rule's ''fundamental flaws'' (including specifically the state budgets found to be unlawful (North Carolina, 550 F.3d 1178), it is difficult to see how new state budgets replacing unlawful budgets and meeting section 110(a)(2)(D)(i)(I) requirements could be viewed as interfering with requirements of the CAA. Indeed, the commenters' approach would severely limit EPA's ability to meet the Court's mandate to develop a new rule consistent with section 110(a)(2)(D)(i)(I). *See* North Carolina, 531 F.3d 921 (explaining that EPA may not require ''some states to exceed the mark'' of eliminating their significant contribution). Further, the other CAA sections cited by the commenters (section 172(e), addressing circumstances where the Administrator relaxes a NAAQS, and section 193, addressing the treatment of requirements promulgated before the November 15, 1990, enactment date for the 1990 Amendments to the Clean Air Act) are not applicable here.

Additionally, while the CAIR budgets may have been tighter than Transport Rule state budgets for a couple of states, the sum of state budgets that were subject to both CAIR and the Transport Rule is lower under the Transport Rule for the annual programs. Moreover, the carryover of the large Title IV allowance bank in CAIR allowed for a great deal more emissions within any given state than is permitted under the Transport Rule.

E. Approach to Power Sector Emission Variability

1. Introduction to Power Sector Variability

Variability is an inherent aspect of the production and delivery of electricity. It follows that variations in state emissions are not only a result of variations in the level of emission control, but also are caused by the inherent variability in power generation. The state budgets do not account for this latter source of variability at the state level. Emission variability is built into the design of power systems, which use a wide mix of power generation sources with varying use and emission patterns to ensure reliability in electric power generation. Variations in weather, demand due to changes in the level of economic activity, the portion of electric generation that is fossil-fuel-fired, the length and number of outages at power generation units, and other factors, can lead to significant variations in the load levels of different power generation sources. Variations in the load levels of sources in any given state cause variations in the level of emissions in that state. Thus, EPA believes it is appropriate, in this rule, to take into account the variations that are caused by inherent variability in power generation. More specifically, variations in these external variables can cause significant fluctuations in state emissions, even when action has been taken to prohibit all emissions within a state that significantly contribute to nonattainment or interfere with maintenance in another state. For this reason, EPA considers variability when determining the state specific requirements in this rule. EPA does so by developing variability limits and assurance levels for each state, as described in this section, that are consistent with the statutory mandate of CAA section 110(a)(2)(D)(i)(I).

Loads on a power system, and thus on power generation sources in a given state that are on the power system, vary over every time interval, changing not only in the short term and seasonally, but also annually. As noted above, load patterns and levels are determined by a multiplicity of factors, including weather, economic activity, the portion of electric generation that is fossil-fuel-fired, and the length and number of outages at power generation units, which vary over time. In particular, weather obviously varies not just from season-to-season but also from year-to-year, and even small changes in annual weather patterns can affect how the power system and power generation sources on the power system operate during a year. For example, load, and the resulting use of generation sources on an interconnected grid to meet load, depend not only on how hot a summer day is, but also on where a heat wave occurs and how long it lasts. Similarly, a relatively cold winter that drives up winter load may also change what generation sources are used to address the increased demand for heat. Thus, the pattern of generation may shift geographically as a weather pattern moves across the country. Because weather and other factors affecting loads, and the patterns of generation used to meet loads, vary over time and from state to state, the resulting level of emissions also varies over time and from state to state.

This variability in emissions is not a result of variation in emission rates, emission controls, or emission control strategies, but instead is a result of the inherent variability in power generation. Patterns of generation change to ensure demand for electricity is met and to ensure continued reliability of the power system. This results in temporal and geographic fluctuations in emissions. In the final Transport Rule, like the proposed rule, EPA explicitly takes account of these changing patterns of generation and the resultant variability in power sector emissions.

As discussed previously, EPA identified a specific amount of emissions that must be prohibited by each state to meet the requirements of CAA section 110(a)(2)(D)(i)(I). EPA also developed state baseline emissions for power generation sources based on projections of state emissions in an average year before the elimination of prohibited emissions, and state budgets for power generation sources based on projections of state emissions in an average year after the elimination of such emissions. However, because of the inherent variability in state-level baseline emissions—resulting from the inherent variability in loads and power system and power generation source operations—state-level emissions will fluctuate from year-to-year even after all significant contribution to nonattainment and interference with maintenance that EPA identified in this final rule are eliminated. In an above average year, emissions may exceed the state budgets which are based on an analysis of projected emissions in an average year. EPA believes that, because baseline emissions are variable for reasons unrelated to the degree of emission control in a state and emissions after the elimination of all significant contribution to nonattainment and interference with maintenance are therefore also variable, it is appropriate to take this variability into account in developing the remedy for meeting the requirements of CAA section 110(a)(2)(D)(i)(I). The variability limits and assurance levels in the final rule account for this inherent variability, while ensuring that emissions within each state that significantly contribute to nonattainment or interfere with maintenance in another state are prohibited. EPA believes this approach is both reasonable in that it reflects the operation of the power system generation in order to maintain electric reliability and consistent with the statutory mandate of CAA section 110(a)(2)(D)(i)(I). For these reasons, EPA

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is finalizing variability limits for each state budget to identify the range of emissions that EPA believes is likely to occur in each state following the elimination of all the state's significant contribution to nonattainment and interference with maintenance.

As discussed above, the air quality-assured trading remedy's state-specific budgets represent each state's emissions in an average year after elimination of significant contribution to nonattainment and interference with maintenance. Because actual base case emissions are likely to vary from projected base case emissions, this remedy incorporates provisions that account for such variability. While the primary purpose of this remedy is to eliminate significant contribution and interference with maintenance, EPA believes variability limits also satisfy several other objectives. The remedy provides the flexibility to deal with real-world variability in the operation of the power system through air quality-assured trading and reduces costs of compliance with emission reduction requirements, while still providing assurance for downwind states that significant contribution to nonattainment and interference with maintenance by upwind states will be eliminated. EPA believes the limited fluctuation in state level emissions that this approach permits is consistent with the statutory mandate of section 110(a)(2)(D)(i)(I) because some geographic and temporal shifting of emissions necessarily results from the inherent variability in power generation and is caused by factors unrelated to the degree of emission control, such as weather, economic activity, and unit availability. Far from excusing any state from addressing emissions within the state that significantly contribute to nonattainment or interfere with maintenance in other states, these variability limits ensure that the system can accommodate the inherent variability in the power sector while ensuring that each state eliminates the amount of emissions within the state, in a given year, that must be eliminated to meet the statutory mandate of section 110(a)(2)(D)(i)(I).

Moreover, the structure of the program, which achieves the required emission reductions through limits on the total number of allowances allocated, assurance provisions, and penalty mechanisms, ensures that the variability limits only allow the amount of temporal and geographic shifting of emissions that is likely to result from the inherent variability in power generation, and not from decisions to avoid or delay the installation of necessary controls. Under the remedy, an individual state can have emissions up to its budget plus the variability limit. However, the requirement that all sources hold allowances covering emissions, and the fact that those allowances are allocated based on state-specific budgets *without* variability, ensure that the total emissions from the states do not exceed the sum of the state budgets. The remedy, therefore, ensures both that total emissions do not exceed the total of the state budgets and that the required emission reductions occur in each state.

This section describes how EPA calculated variability limits for each state to achieve this goal.

2. Transport Rule Variability Limits

EPA performed analyses using historical data to demonstrate that there is year-to-year variability in base case emissions (even when emission rates for all units are held constant) and to quantify the magnitude of this variability.

The focus of the analysis is on quantifying the magnitude of the inherent year-to-year variability in state-level EGU emissions independent of measures taken to control those emissions (and thus due only to changes in electricity generation within each state). EPA used this analysis to set variability limits as part of the remedy to ensure that states are eliminating their significant contribution to nonattainment and interference with maintenance to protect air quality.

As discussed in detail below, EPA is finalizing the Transport Rule with 1-year variability limits calculated using a modified approach from the one described in the proposal. EPA is not including the proposal's 3-year variability limits in the final Transport Rule. EPA received comments that the 3-year variability limits increased program costs and diminished compliance flexibility without delivering any additional air quality benefits. EGU owners and operators expressed concern that 3-year variability limits would be impracticable to implement and that the 1-year variability limits themselves would be adequately stringent to ensure elimination of significant contribution to nonattainment and interference with maintenance in each state.

After further consideration, EPA has concluded that 3-year variability limits would be unnecessary, would be difficult to anticipate, and would not have a measurable impact on air quality benefits. EPA has determined that annual limits are sufficient to eliminate significant contribution to nonattainment and interference with maintenance in all upwind states while accommodating the historically observed year-to-year fluctuation in state-level EGU emissions even at the same rate of emissions control in a given state.

In the proposal, EPA used statistical methods to derive the 3-year variability limit directly from the 1-year variability limit, meaning that the two are statistically equivalent in the long run under certain statistical assumptions. Primarily, these assumptions were that the variation in electric demand around the budget is random from year-to-year and that, when the annual emissions are averaged over a multi-year time period, the average emissions per year will equal the state's budget. The first assumption was also made in the assessment of the historical year-to-year variation in heat input in developing the 1-year limit (*see* section 2 of the ''Power Sector Variability Final Rule TSD'' for more details). Regarding the second assumption, since the state-by-state emission budgets are based on the availability of emission reductions at an equal marginal cost level, EPA expects the sources in each of the upwind states to make these cost-effective reductions and to meet the emission budgets each year, on average.

Since the 3-year variability limit was based on average year-to-year variability over a longer time horizon, EPA notes that a random ordering of those years could yield 2 above-average years in a row. If, by chance, a third above-average year were to follow, the state could face violation of the 3-year limit, even if over a time period longer than 3 years, that state would never have exceeded the statistically-equivalent 1-year variability limit and its annual emissions would have averaged to the level of its budget. Effectively, this means that imposing a multi-year variability limit would erode the 1-year variability limit's ability to accommodate historically observed year-to-year variability in state-level EGU emissions (due only to generation changes), and it would do so without providing any additional air quality benefits or protection for downwind areas (since the average emissions over the long time horizon equal the level of the budget).

For more details about the relationship between the 1- and 3-year limits, see the discussions in section 3 of the ''Power Sector Variability'' TSD from the proposed Transport Rule, which describes the derivation of the 3-year limit from the 1-year variability and section 3 of the ''Power Sector Variability Final Rule TSD'', which describes the results of a numerical

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simulation showing that the 1- and 3-year limits are statistically indistinguishable and, thus, redundant over the course of the program to accommodate year-to-year variability.

While EPA expects the yearly emissions in each state, on average, to equal the level of the budgets, EPA also estimated the air quality impacts of 5, 10, 15, and 20 percent emission variability using the air quality assessment tool, which is presented in section 4 of the ''Power Sector Variability Final Rule TSD.'' That analysis shows that year-to-year fluctuations of up to 20 percent in SO_2 emissions from upwind states linked to a given downwind receptor do not undermine the ability of the Transport Rule programs to resolve nonattainment or maintenance concerns at that receptor. The analysis presented in the TSD focuses on SO_2 emissions and was designed to examine the sensitivity of downwind air quality to upwind EGU emission levels. The share of total SO_2 emitted by EGUs is significantly larger than the share of total NO_X emitted by EGUs. For example, in the states for which EPA modeled base case contributions of these pollutants, EGUs accounted for 74 percent of total SO_2, 14 percent of total annual NO_X, and 15 percent of total ozone-season NO_X emissions. Therefore, when varying EGU emissions only, downwind air quality would be most sensitive to upwind variations in SO_2, because relative variations in EGU SO_2 emissions have a greater impact on total SO_2 emissions than the same relative variation in EGU NO_X emissions would have on total NO_X emissions affecting downwind air quality. Because the Transport Rule only affects upwind emissions from EGU sources, downwind air quality would be more sensitive to variability in upwind state SO_2 emissions under this rule than variability in upwind state NO_X emissions under this rule (given that the rule affects a smaller scope of total NO_X emissions compared to the scope affected of total SO_2 emissions). Thus, EPA chose to analyze the ''worst-case'' potential downwind air quality impacts from year-to-year variability above upwind state SO_2 budgets, and EPA therefore believes that its findings from this analysis are valid for ascertaining the potential downwind air quality impacts from variation at those levels in both SO_2 and NO_X under the Transport Rule programs.

Furthermore, because the state budgets are based directly on IPM modeling of electric generation when cost-effective emission reductions have been achieved, sources within each state should have the same incentive to meet that budget, on average, in any given year. Additional EPA analysis supports the claim that states would be no more likely to exceed 1-year variability limits without the 3-year limits than with the 3-year limits. *See* the ''Power Sector Variability Final Rule TSD'' for more details on this statistical analysis. Finally, because the state budgets (and thus the total amount of allowances available) are fixed and every covered source must hold allowances covering its emissions, it is not feasible for all, or even many, states to repeatedly exceed their budgets.

The approach calculated the standard deviation in state-level heat input from units expected to be covered by the final Transport Rule over an 11-year time period (2000 through 2010), from which the 95th percent confidence level was calculated. EPA divided this value by the mean to get the percentage variation in heat input. The two-tailed 95th percent confidence level is the equivalent of the 97.5 percent upper (single-tailed) confidence level. This approach yielded an average year-to-year heat input variability for each state, as a proxy for historic year-to-year variability in state-level EGU emissions while holding emission rates constant. The result, expressed as a percentage, conveys the maximum degree to which EGU emissions at the state level may be expected with 95th percent confidence to vary around a given target (*i.e.,* budget) from year-to-year, on average, based on the statistical analysis of historic heat input over the 2000 through 2010 time period.

From the state-by-state variability calculations, EPA identified a single variability level (percentage) for each of the annual and ozone-season programs based on the historic variability measured at units in covered states on an annual basis and an ozone-season basis, respectively. In the proposal, EPA ''identified a single set of variability levels * * * to apply to all states in order to make the application of the variability limits straightforward rather than developing state-by-state percentage variability values'' (75 FR 45293). In the final rule, EPA is taking the straightforward approach of identifying a single set of variability levels to apply to all states because EPA has determined that it is reasonable to afford all states under the Transport Rule programs the extent of measured historic variability experienced by any Transport Rule state during 2000 through 2010. In the variability analysis for the final rule, EPA identified Tennessee as having the highest measured historic variability of annual heat input of 18 percent, and Virginia as having the highest measured historic variability of ozone-season heat input of 21 percent. Because the percentage of variability in Tennessee on an annual basis and in Virginia on an ozone-season basis are reasonably likely to occur in each of the other states in the future, EPA believes it is appropriate to apply an 18 percent annual variability limit to all states covered by the annual SO_2 and NO_X programs and a 21 percent ozone-season variability limit to all states covered by the ozone-season NO_X program.[54]

EPA's analysis of historic heat input variability in multiple states over the 2000 to 2010 baseline yields a range of potential year-to-year variability values for state-level EGU emissions. As discussed above, any one state's measured variability (in this case, from 2000 to 2010) is due to a multiplicity of factors. These factors include, but are not limited to, variation in weather, variation in demand due to increased or decreased level of economic activity, variation in the portion of electric generation that is fossil-fuel-fired, and variation in the length and number of outages at power generation units, and these individual factors may sometimes act in concert and may other times be offsetting.

The mix and levels of factors present in a state from year-to-year can lead to variation of state-level emissions above and below the level for the state under average conditions. Because the levels of the various factors are difficult to predict on a year-to-year basis for an individual state, the resulting variability in state-level emissions is difficult to predict. Moreover, because the electric generation, transmission, and distribution system in the eastern half of the U.S. is highly integrated, year-to-year variation in these factors in one state can cause year-to-year variability in state-level emissions both in that state and in other states on the system. For example, increased demand due to extreme weather or increased economic activity in one state can be met through increased generation and emissions in a number of states.

Because these factors can vary year-to-year in every state in ways that are difficult to predict and can affect other states, EPA maintains that the maximum variability measured in one state for a discrete period (2000–2010) is

[54] The six states in the supplemental proposal for inclusion in the Transport Rule's ozone-season NO_X program have measured historic ozone-season variability that would be adequately covered by this final rule's ozone-season NO_X variability level (21 percent). Please see the ''Power Sector Variability Final Rule TSD'' for more details.

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reasonably likely to occur in the future in any of the states in the region. Consequently, EPA believes that it is reasonable to use the maximum historic percentage variability figure as a proxy for the percentage variability that any of the states is likely to experience in the future. Although EPA is therefore using a uniform percentage figure for variability, EPA applies that percentage figure to each state-specific budget so that variability in tons of emissions is determined on a state-specific basis. That state-specific number is used in determining whether the assurance provisions and penalty are triggered in the specific state. EPA also believes that it is appropriate to accommodate this potential future variability at the state level if and only if it can be accommodated without undermining the programs' beneficial impacts on downwind air quality that eliminate significant contribution to nonattainment or interference with maintenance of the NAAQS assessed in this rulemaking (*see* the ''Power Sector Variability Final Rule TSD'' for more information on this analysis). The Transport Rule identifies and quantifies, on a state-by-state basis, the emissions in each state that significantly contribute to nonattainment or interfere with maintenance in another state. This is done by analyzing specific air pollution linkages between each upwind state and each downwind maintenance or nonattainment receptor. Nonetheless, it is clear from the air quality analyses that the air quality outcome at a given downwind receptor is a function of the cumulative emissions from all upwind states and the receptor's home state. Once the Transport Rule emission reduction requirements are implemented in all states subject to the programs, EPA's analysis shows that the impact on a downwind receptor of any single upwind state's year-to-year fluctuation of up to 20 percent in SO_2 emissions would be so limited as to not disturb that receptor's ability to maintain or attain the NAAQS analyzed in this rulemaking. Therefore, to the extent that such variability has been measured in historic data in any state subject to the Transport Rule programs, it is reasonable to provide for potential future variability in Transport Rule states within the scope of what EPA's analysis shows to preserve downwind air quality gains achieved by the Transport Rule programs.

The approach to establishing variability limits in the final rule modifies the approach from the proposed rule in two ways. First, EPA is applying only a percentage variability limit to each budget in the final rule, whereas the proposed rule applied the greater of a percentage or an absolute tonnage variability limit to each budget. EPA explained in the proposal that it was necessary to impose both a percentage and a tonnage limit due to the inclusion of ''states with small numbers of units where expected variability would be more pronounced in percentage terms'' (75 FR 45293). However, the states with the smallest numbers of units included at proposal (such as Connecticut and the District of Columbia) are not covered by any of the final Transport Rule's programs. In the final rule's variability analysis, Tennessee has the highest measured annual variability percentage and Virginia has the highest measured ozone-season variability percentage. Both of these states have a sufficient number of units for the percentage variability findings to be representative of variability in all of the Transport Rule states; therefore, it is not necessary to impose a tonnage limitation in the final rule.

Second, EPA has expanded the historic baseline of the variability analysis to consider heat input data from 2000 through 2010, as compared to 2002 through 2008 at proposal, and EPA has also expanded the dataset to include all units expected to be covered by the final Transport Rule's programs. EPA received a number of comments that the proposal's variability limits were too stringent in part because they relied on too short a historical baseline that failed to capture the full extent of long-run year-to-year variability. EPA agrees with these comments and believes that the historic baseline modification described above supports variability limits in the final rule that are a better approximation of future potential year-to-year variability in state-level EGU emissions around the budgets as a function of inherent variability in baseline state-level EGU operations. EPA believes the 2000 through 2010 historic baseline supports a more accurate approximation of year-to-year variability in state-level EGU operations than previously measured on a 2002 through 2008 baseline.

Some commenters expressed the view that allowing variability limits in addition to state budgets undermines the requirements of CAA section 110(a)(2)(D)(i)(I) to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS in downwind states. EPA disagrees with these comments. As explained above, EPA finds that year-to-year variability is an inherent characteristic of power sector emissions whether or not such emissions are controlled by state budgets; the future year-to-year variability is a component of the sector's emissions baseline before emission reductions are required. As done for proposal, EPA has analyzed the impact of allowing emissions from upwind states in a given year to rise above the budgets but within the variability limits allowed in the final rule. This analysis shows that emission fluctuations around the budgets but within the variability limits will not undermine the downwind air quality gains achieved by the implementation of the Transport Rule budgets, and therefore the variability limits cannot be said to undermine the elimination of significant contribution to nonattainment or interference with maintenance achieved under the Transport Rule programs. Based on historical data and projected air quality impacts, the Agency believes that states will have sufficient flexibility and room to operate within the final rule's variability limits while addressing all emissions identified as significantly contributing to nonattainment or interfering with maintenance in other states.

F. Variability Limits and State Emission Budgets: State Assurance Levels

As explained above, EPA applied the variability levels on a state-by-state basis to calculate specific emission budgets with variability limits. The state budget plus the variability limit is also called the ''state assurance level.'' Table VI.F–1 shows final state budgets, variability limits, and assurance levels by state for SO_2 emissions. Table VI.F–2 shows final state budgets, variability limits, and assurance levels by state for annual NO_X emissions. Table VI.F–3 shows final state budgets, variability limits, and assurance levels by state for ozone-season NO_X emissions.

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TABLE VI.F–1—STATE BUDGETS, VARIABILITY LIMITS, AND ASSURANCE LEVELS FOR SO_2 EMISSIONS

	Emission budget (tons)		Emission variability limit (tons)		State emissions assurance level (tons)	
	2012–2013	2014 and beyond	2012–2013	2014 and beyond	2012–2013	2014 and beyond
Alabama	216,033	213,258	38,886	38,386	254,919	251,644
Georgia	158,527	95,231	28,535	17,142	187,062	112,373
Illinois	234,889	124,123	42,280	22,342	277,169	146,465
Indiana	285,424	161,111	51,376	29,000	336,800	190,111
Iowa	107,085	75,184	19,275	13,533	126,360	88,717
Kansas	41,528	41,528	7,475	7,475	49,003	49,003
Kentucky	232,662	106,284	41,879	19,131	274,541	125,415
Maryland	30,120	28,203	5,422	5,077	35,542	33,280
Michigan	229,303	143,995	41,275	25,919	270,578	169,914
Minnesota	41,981	41,981	7,557	7,557	49,538	49,538
Missouri	207,466	165,941	37,344	29,869	244,810	195,810
Nebraska	65,052	65,052	11,709	11,709	76,761	76,761
New Jersey	5,574	5,574	1,003	1,003	6,577	6,577
New York	27,325	18,585	4,919	3,345	32,244	21,930
North Carolina	136,881	57,620	24,639	10,372	161,520	67,992
Ohio	310,230	137,077	55,841	24,674	366,071	161,751
Pennsylvania	278,651	112,021	50,157	20,164	328,808	132,185
South Carolina	88,620	88,620	15,952	15,952	104,572	104,572
Tennessee	148,150	58,833	26,667	10,590	174,817	69,423
Texas	243,954	243,954	43,912	43,912	287,866	287,866
Virginia	70,820	35,057	12,748	6,310	83,568	41,367
West Virginia	146,174	75,668	26,311	13,620	172,485	89,288
Wisconsin	79,480	40,126	14,306	7,223	93,786	47,349

Note: Budgets, limits, and assurance levels apply to each state's emissions from covered sources, as defined by this final rule, only.

TABLE VI.F–2—STATE BUDGETS, VARIABILITY LIMITS, AND ASSURANCE LEVELS FOR ANNUAL NO_X EMISSIONS

	Emission budget (tons)		Emission variability limit (tons)		State emissions assurance level (tons)	
	2012–2013	2014 and beyond	2012–2013	2014 and beyond	2012–2013	2014 and beyond
Alabama	72,691	71,962	13,084	12,953	85,775	84,915
Georgia	62,010	40,540	11,162	7,297	73,172	47,837
Illinois	47,872	47,872	8,617	8,617	56,489	56,489
Indiana	109,726	108,424	19,751	19,516	129,477	127,940
Iowa	38,335	37,498	6,900	6,750	45,235	44,248
Kansas	30,714	25,560	5,529	4,601	36,243	30,161
Kentucky	85,086	77,238	15,315	13,903	100,401	91,141
Maryland	16,633	16,574	2,994	2,983	19,627	19,557
Michigan	60,193	57,812	10,835	10,406	71,028	68,218
Minnesota	29,572	29,572	5,323	5,323	34,895	34,895
Missouri	52,374	48,717	9,427	8,769	61,801	57,486
Nebraska	26,440	26,440	4,759	4,759	31,199	31,199
New Jersey	7,266	7,266	1,308	1,308	8,574	8,574
New York	17,543	17,543	3,158	3,158	20,701	20,701
North Carolina	50,587	41,553	9,106	7,480	59,693	49,033
Ohio	92,703	87,493	16,687	15,749	109,390	103,242
Pennsylvania	119,986	119,194	21,597	21,455	141,583	140,649
South Carolina	32,498	32,498	5,850	5,850	38,348	38,348
Tennessee	35,703	19,337	6,427	3,481	42,130	22,818
Texas	133,595	133,595	24,047	24,047	157,642	1 57,642
Virginia	33,242	33,242	5,984	5,984	39,226	39,226
West Virginia	59,472	54,582	10,705	9,825	70,177	64,407
Wisconsin	31,628	30,398	5,693	5,472	37,321	35,870

Note: Budgets, limits, and assurance levels apply to each state's emissions from covered sources, as defined by this final rule, only.

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TABLE VI.F–3—STATE BUDGETS, VARIABILITY LIMITS, AND ASSURANCE LEVELS FOR OZONE-SEASON NO_X EMISSIONS

	Emission budget (tons)		Emission variability limit (tons)		State emissions assurance level (tons)	
	2012–2013	2014 and beyond	2012–2013	2014 and beyond	2012–2013	2014 and beyond
Alabama	31,746	31,499	6,667	6,615	38,413	38,114
Arkansas	15,037	15,037	3,158	3,158	18,195	18,195
Florida	27,825	27,825	5,843	5,843	33,668	33,668
Georgia	27,944	18,279	5,868	3,839	33,812	22,118
Illinois	21,208	21,208	4,454	4,454	25,662	25,662
Indiana	46,876	46,175	9,844	9,697	56,720	55,872
Kentucky	36,167	32,674	7,595	6,862	43,762	39,536
Louisiana	13,432	13,432	2,821	2,821	16,253	16,253
Maryland	7,179	7,179	1,508	1,508	8,687	8,687
Mississippi	10,160	10,160	2,134	2,134	12,294	12,294
New Jersey	3,382	3,382	710	710	4,092	4,092
New York	8,331	8,331	1,750	1,750	10,081	10,081
North Carolina	22,168	18,455	4,655	3,876	26,823	22,331
Ohio	40,063	37,792	8,413	7,936	48,476	45,728
Pennsylvania	52,201	51,912	10,962	10,902	63,163	62,814
South Carolina	13,909	13,909	2,921	2,921	16,830	16,830
Tennessee	14,908	8,016	3,131	1,683	18,039	9,699
Texas	63,043	63,043	13,239	13,239	76,282	76,282
Virginia	14,452	14,452	3,035	3,035	17,487	17,487
West Virginia	25,283	23,291	5,309	4,891	30,592	28,182

Note: Budgets, limits, and assurance levels apply to each state's emissions from covered sources, as defined by this final rule, only.

See section VII.E for the discussion of how variability limits and state assurance levels are used in the implementation of assurance provisions for the air quality-assured trading programs.

G. How the State Emission Reduction Requirements Are Consistent With Judicial Opinions Interpreting the Clean Air Act

The methodology described in this notice quantifies states' significant contribution to nonattainment and interference with maintenance in a manner that is consistent with the decisions of the DC Circuit. As discussed previously, the DC Circuit has issued two significant decisions addressing the requirements of 110(a)(2)(D)(i)(I). The first opinion largely upheld the NO_X SIP Call, *Michigan,* 213 F.3d 663, and the second found significant flaws in CAIR, *North Carolina,* 531 F.3d. 896. In both cases, the Court considered aspects of the methodology used by EPA to identify emissions that, pursuant to section 110(a)(2)(D)(i)(I), must be eliminated due to their impact on air quality in downwind states. EPA believes that the methodology used in this final rule is consistent with both opinions and rectifies the flaws the *North Carolina* court identified with the methodology used in CAIR. The methodology used for this rule relies on state-specific data to analyze each individual state's significant contribution, uses air quality considerations in addition to cost considerations to identify each state's significant contribution, and gives independent meaning to the ''interference with maintenance'' prong. This methodology is then applied in a reasonable manner consistent with the relevant judicial opinions.

In *North Carolina,* the Court held that EPA's approach to evaluating significant contribution was inadequate because, by evaluating only whether emission reductions were highly cost effective ''at the regional level assuming a trading program'', it failed to conduct the required state-specific analysis of significant contribution. *See id.* at 907. EPA, the Court concluded, ''never measured the 'significant contribution' from sources within an individual state to downwind nonattainment areas.'' *Id.* The Court did not, however, disturb the air-quality-based methodology used by EPA to identify the states with contributions large enough to warrant further consideration.

For this rule, EPA uses a first step similar to that used in CAIR to identify the states with relatively large contributions. However, in contrast to CAIR, it then uses a state-specific analysis. Instead of identifying a single emission level that could be achieved by the application of highly cost effective controls in the region, EPA determines, on a state-by-state basis, what reductions could effectively be achieved by sources in each state. EPA's new approach does not, as the CAIR methodology did, establish a regional cap on emissions that is then divided into state budgets that set the emission reduction requirements for each state. Instead, EPA develops, for each covered state, emission budgets based on the reductions achievable at a particular cost per ton in that particular state, taking into account the need to ensure reliability of the electric generating system. The selected cost/ton levels reflect consideration of both cost factors and air quality factors including the estimated impact of upwind states' emissions on each downwind receptor.

In addition, in developing this approach, EPA was guided by the Court's holdings regarding the use of cost to identify significant contribution. Specifically, the Court held in *Michigan* that EPA could ''in selecting the 'significant' level of 'contribution' under section 110(a)(2)(D)(i)(I), choose a level corresponding to a certain reduction in cost.'' *North Carolina,* 531 F.3d at 917 (citing *Michigan,* 213 F.3d at 676–77). This holding also supported the Court's conclusion in *Michigan* that it was acceptable for EPA to apply a uniform cost-criterion across states. *See Michigan,* 213 F.3d at 679. In the CAIR case, the Court rejected EPA's analysis, not because it relied on cost considerations to identify significant contribution, but because it found that EPA had failed to draw the significant contribution line at all. *See North Carolina,* 531 F.3d at 918 (''* * * here EPA did not draw the [significant contribution] line at all. It simply verified sources could meet the SO_2 caps with controls EPA dubbed 'highly

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cost-effective.' ''). The holdings in *Michigan* regarding the use of cost and a uniform cost-criterion across states were left undisturbed. *See, e.g., North Carolina,* 531 F.3d at 917 (explaining that in *Michigan* the Court held that ''EPA may 'after [a state's] reduction of all [it] could * * * cost-effectively eliminate[],' consider 'any remaining contribution insignificant''). In fact, the Court acknowledged that, based on the *Michigan* holdings, the measurement of a state's significant contribution need not ''directly correlate with each state's individualized air quality impact on downwind nonattainment relative to other upwind states.'' *North Carolina,* 531 F.3d at 908.

For these reasons, EPA determined that it was appropriate in this rulemaking to consider the cost of controls to determine what portion of a state's contribution is its ''significant contribution.'' However, EPA also heeded the *North Carolina* Court's warning that ''EPA can't just pick a cost for a region, and deem 'significant' any emissions that sources can eliminate more cheaply.'' *North Carolina,*, 531 F.3d at 918. Thus, in this rulemaking, EPA departs from the practice used in the NO_X SIP Call and in CAIR of evaluating, based solely on the cost of control required in other regulatory environments, what controls would be considered ''highly-cost-effective.'' Instead, as part of its determination of a reasonable cost per ton for upwind state control, EPA evaluates the air quality impact of reductions at various cost levels and considers the reasonableness of possible cost thresholds as part of a multi-factor analysis.

In addition, the methodology used in this rulemaking gives independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I). In *North Carolina,* the Court concluded that CAIR improperly ''gave no independent significance to the 'interfere with maintenance' prong of section 110(a)(2)(D)(i)(I) to separately identify upwind sources interfering with downwind maintenance.'' *North Carolina,* 531 F.3d at 910. EPA rectified this flaw in this rulemaking by separately identifying downwind ''nonattainment sites'' and downwind ''maintenance sites.'' EPA decided to consider upwind states' contributions not only to sites that EPA projected would be in nonattainment, but also to sites that, based on the historic variability of their emissions, EPA determined may have difficulty maintaining the relevant standards. The specific mechanism EPA used to implement this approach is described in detail in section V.C, previously. For annual $PM_{2.5}$, this approach identified 16 maintenance sites in addition to the 32 nonattainment sites identified in the analysis of nonattainment receptors. For 24-hour $PM_{2.5}$ this approach identified 38 maintenance sites in addition to the 92 nonattainment sites identified in the analysis of nonattainment receptors. For ozone it identified 16 maintenance sites in addition to the 11 ozone nonattainment sites identified.

EPA applied this methodology using available information and data to measure the emissions from states in the eastern United States that significantly contribute to nonattainment or interfere with maintenance in downwind areas with regard to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. Although EPA has not completely quantified the total significant contribution of these states with regard to all existing standards, EPA has determined, on a state-specific basis, that the emissions prohibited in the FIPs are either part of or constitute the state's significant contribution to nonattainment and interference with maintenance. Thus, elimination of these emissions will, at a minimum, make measurable progress towards satisfying the section 110(a)(2)(D)(i)(I) prohibition on significant contribution to nonattainment and interference with maintenance.

VII. FIP Program Structure To Achieve Reductions

A. Overview of Air Quality-Assured Trading Programs

EPA is finalizing an air quality-assured trading remedy that is substantially similar to the preferred trading remedy presented in the proposal. Key differences from the preferred trading remedy in the proposal include:

- Recalculated state budgets and variability limits (*i.e.*, state assurance levels) based on updated modeling;
- Simplified variability limits for 1-year application only;
- Revised allocation methodology for existing and new units and revised new unit set-asides for new units in Transport Rule states and new units potentially locating in Indian country;
- Changed start of assurance provisions to 2012 and increased assurance provision penalties; and
- Removed opt-in provisions.

In the final rule, as in the proposed rule, EPA is promulgating FIPS to require SO_2 and NO_X reductions from power plants in jurisdictions[55] that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS, and/or the 2006 24-hour $PM_{2.5}$ NAAQS. These FIPs establish state-specific emission control requirements using state budgets starting in 2012, with a second phase of SO_2 reductions in some states in 2014. Section IV explains EPA's authority to issue FIPs.

The air quality-assured trading remedy in the final rule allows interstate trading to account for variability in the electricity sector, but also includes assurance provisions to ensure that the necessary emission reductions occur within each covered state. The assurance provisions restrict EGU emissions within each state to the state's budget plus the variability limit and ensure that every state is making reductions to eliminate the significant contribution to nonattainment and interference with maintenance that EPA has identified. While EPA proposed to impose these assurance provisions starting in 2014, the final rule implements these provisions starting in 2012 (*see* section VII.E of this preamble). Additionally, the final FIPs include penalty provisions adequate to ensure that the state budget with the variability limit will not be exceeded.

In the final rule, as in the preferred trading remedy discussed in the proposed rule, state-specific emission budgets without the variability limits are used to determine the number of emission allowances allocated to sources in each state. An EGU source is required to hold one SO_2 or one NO_X allowance, respectively, for every ton of SO_2 or NO_X emitted during the control period. Banking of allowances for use or trading in future years is allowed.

The final rule establishes four interstate trading programs, each starting in 2012: two for annual SO_2, one for annual NO_X, and one for ozone-season NO_X. One SO_2 trading program is for sources in states (referred to as SO_2 Group 1) that need to make larger reductions to eliminate their significant contribution, while the second is for sources in states (referred to as SO_2 Group 2) that need to make smaller reductions. A source in a Group 1 state can only use SO_2 allowances allocated to Group 1 states for compliance with

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[55] Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. As discussed in section III, in a separate notice, EPA is proposing to include Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin in the ozone-season NO_X requirements.

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the SO_2 trading program. A source in a Group 2 state can only use SO_2 allowances allocated to Group 2 states for compliance with the SO_2 trading program. For compliance in the annual NO_X and ozone-season NO_X trading programs respectively, sources may use annual NO_X and ozone-season NO_X allowances allocated for any state, even if that state is in a different group for SO_2 than the source's state. Four sets of new emission allowances based on the new state-specific budgets without variability are allocated to sources, one set for each of the four trading programs. Each state has the option of replacing these FIPs with state rules. EPA believes that this remedy meets the concerns raised by the Court in the 2008 *North Carolina* decisions which remanded CAIR to EPA.

In the proposed rule, EPA took comment on all aspects of the preferred trading remedy and on two alternative regulatory options: (1) intrastate trading; and (2) direct control. EPA also took comment on a trading ratios approach.

Comments on the Preferred Trading Remedy: The great majority of public comments supported the preferred trading remedy. Most of these commenters voiced their support for the broadest possible trading mechanism because it allows for the most cost-effective implementation of any emission controls. Commenters noted that flexibility is always needed in the early years of new programs. Further, commenters favoring the preferred remedy agreed with EPA that, by using state-specific control budgets and allowing for interstate trading, the preferred remedy provided electricity generators the flexibility to undertake the most cost-effective reductions while assuring that the resulting reductions occur within the individual states.

Some commenters that supported the preferred remedy felt that, while not ideal, the interstate trading remedy was preferable to the alternative options of intrastate trading or direct control. Many commenters that supported the preferred remedy felt that the intrastate trading remedy and direct control remedy options offer minimal flexibility from a compliance perspective. They stated that this lack of flexibility would unnecessarily increase the cost of emission reductions.

Other commenters who generally support the preferred remedy cited concerns about the level of complexity in the assurance provisions. One commenter surmised that the preferred option creates significant risk where a company could unexpectedly find itself in a noncompliance situation due to the after-the-fact variability analysis. Another said that the rule's features needlessly reduce the system's efficiency and increase complexity. These commenters generally preferred unlimited trading, noting that EPA has proven success with Title IV, the NO_X SIP Call, and CAIR unlimited interstate trading programs and that allowing unrestricted interstate trading would increase flexibility to meet reduction goals and minimize increases in power costs.

EPA is finalizing the preferred trading remedy for the following reasons. EPA believes this approach is the most cost-effective and practical way to comply with the Court decision in *North Carolina* to ensure that all emissions in a given state that EPA has identified as significantly contributing to downwind nonattainment or interfering with maintenance are eliminated. The vast majority of public commenters agree. In addition, this approach provides the most flexibility for sources while meeting the Clean Air Act requirements and protecting public health. As a result, potential innovations and resulting cost savings are more likely to be found and implemented. Based on historical experience (see the Transport Rule proposal, 75 FR 45315), EPA has shown that the results offered by a flexible trading approach (*e.g.*, flexible compliance choices, incentives to reduce emissions early and in the highest emitting areas, 100 percent compliance with requirements) are substantial. A large number of commenters have corroborated this assessment. As summarized in the proposal, EPA believes that the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost-effective manner, such as installing controls, changing fuels, reducing utilization, buying allowances, or any combination of these actions. Interstate trading with assurance provisions provides additional regulatory flexibility that promotes the power sector's ability to operate as an integrated, interstate system and to provide electric reliability.

Comments on Intrastate Trading: A few commenters favored the first alternative, intrastate trading. One commenter who favored intrastate trading stated that many power plants have avoided investment in pollution controls by buying allowances from other plants, affecting local air quality improvement. EPA notes that this Transport Rule aims to address emissions from one state that significantly contribute to nonattainment or interfere with maintenance of certain NAAQS in other states. Local air quality issues are directly addressed by other provisions in the Clean Air Act.

Several commenters raised concerns about the intrastate trading approach. Some stated, as EPA noted in the proposal, that the intrastate trading option would be more resource intensive, more complex, less flexible, and potentially more susceptible to market manipulation than the other options. In addition, some commenters felt that this alternative would provide less flexibility to ensure electric reliability than the preferred approach, resulting in greater private costs to the power sector and greater social costs for consumers.

EPA is not finalizing the intrastate trading option for the following reasons. As EPA expressed in the proposal and as commenters have agreed, the intrastate trading option would be more resource intensive (both for EPA and for sources), more complex, less flexible, and potentially more susceptible to market manipulation than the preferred trading approach that EPA is finalizing. The intrastate trading option would be more costly and less transparent due to the large number of trading programs that would be operated simultaneously and the large number of annual auctions that would be held every year to address the issues of market power within states. This option would also result in a greater burden for participants operating EGUs in multiple states.

Comments on Direct Control Option: Several commenters favored the second alternative, direct control. One commenter stated that direct control—allowing no trading—was the option best aligned with the 2008 Court decisions. EPA disagrees with this comment for the reasons given below and because, as explained in this rule, EPA believes the air quality-assured trading remedy finalized today is consistent with the decisions of the DC Circuit in *North Carolina*.

Some commenters, who support direct control, voiced concerns that the other emission trading approaches would disadvantage poor and minority communities or allow increased emission impacts in neighborhoods near power plants. EPA notes that a direct control approach would not require controls on all plants in a state, but only on a sufficient number to address the transport requirements under section 110(a)(2)(d)(i)(I) that this rule addresses, and therefore would not necessarily mandate controls on each neighborhood power plant.

In addition, EPA has conducted an analysis of the effects of the Transport

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Rule on environmental justice and other vulnerable communities. We concluded that, similar to our experience with the Acid Rain Program,[56] many environmental justice communities are expected to see large health benefits, and none are expected to experience any disbenefits, from implementing an air quality-assured trading program. The results of this analysis are presented in section XII of this preamble and Chapter 5 of the RIA for this rule. In addition, the CAA provides flexibility for state and local authorities to impose stricter limits on sources to address specific local air quality concerns. Such limits are independent of the requirements in this rule, and compliance with Transport Rule requirements in no way excuses a source from complying with other CAA or state law requirements.

Several commenters raised concerns with the direct control approach. One commenter felt that issues with electricity market reliability could occur during high electricity demand periods if sources ceased operations due to approaching their emission rate limitations under a direct control remedy. Another commenter was concerned that applying emission rates under a direct control remedy to small municipal units would cause disproportionate impacts on power plants where pollution control is more expensive. Other commenters cited concerns that EPA's proposed within-state company-wide averaging provision in the direct control proposed alternative (designed to allow some flexibility for sources) would place companies with fewer units at a disadvantage compared to companies with more units. EPA generally agrees with the commenters concerns and has decided not to finalize the direct control remedy for the following reasons. EPA modeling projects that the direct control alternative would result in fewer emission reductions and higher costs compared to the air quality-assured trading remedy. EPA analysis indicates that it is not necessary to implement a direct control approach in order to protect vulnerable and sensitive populations or environmental justice communities. Also, the direct control approach would result in fewer compliance options because a direct control approach would directly regulate individual sources by setting unit-level emission rate limits. This lack of flexibility could lead to potential increases in reliability risks in the electric power system and fewer opportunities for potential technological innovations that reduce emissions further and/or lower costs. For these reasons, EPA believes that this approach is inferior to the air quality-assured trading remedy.

Other Comments: A handful of commenters mentioned the trading ratios approach, though none favored it as a viable alternative. One commenter said the trading ratios approach was not consistent with CAA section 110(a)(2)(D) requirements that reductions in emissions occur in particular geographic locations. Other commenters agreed that it was administratively unworkable and would be difficult to implement due to the complexity and variety of meteorological conditions. EPA generally concurs with the commenters. In the proposal, EPA noted that it would not be possible under this approach, as contemplated, to include enforceable legal requirements to ensure that a specific state's emissions remain below a specified level or to ensure that a specific amount of reductions occur within a particular state. EPA specifically requested comment on whether a ratios trading program could be designed to provide such legal assurances. Of the few comments received, none offered such a solution. For these reasons, EPA is not finalizing this approach.

Some commenters offered additional suggestions, such as: unrestricted trading; using different authorities in the CAA to address interstate transport such as section 110(k)(5) and section 126; and an approach that would replace the assurance provisions by a system using both emission allowances usable (as well as bankable) in any state and assurance allowances usable (but not bankable) in only the state for which they would be issued. While EPA appreciates the thoughtful and constructive comments, we did not find any of these suggestions improved our ability to address interstate transport under CAA section 110(a)(2)(D)(i)(I), in line with the Court decision, in an administratively practical way.

Several commenters liked the idea of establishing unit-by-unit short-term and long-term performance standards/emission rates but suggested adding an overlaid cap and trade program. EPA believes the air quality-assured trading remedy finalized today is consistent with the decisions of the Court in *North Carolina* and will ensure the reductions necessary to meet statutory requirements.

For the 2012–2013 period, EPA took comment on whether the assurance provisions are needed, since the state-specific budgets would be based on known air pollution controls and the penalty provisions would be adequate to ensure that the budget, including a variability limit, would not be exceeded. Further, EPA proposed to use two variability limits: a 1-year limit, based on the year-to-year variability in emissions relative to the proposed budgets; and a 3-year limit based on the variability in a 3-year average relative to the proposed budget.

Based on comments on the assurance provisions (*see* section VII.E of this preamble) and variability limits (*see* section VI.E.2 of this preamble), EPA is finalizing the Transport Rule with state budgets plus variability limits and assurance provisions starting in 2012 for all of the trading programs. EPA sees an immediate need to ensure that emissions within a state do not exceed the state budget plus the variability limitation in order to comply with the Court's opinion. Further, commenters stated that the 3-year variability limit increased costs and unnecessarily complicated the trading programs. As explained in section VI.E.2, EPA is finalizing the 1-year variability limit starting in 2012, but not the 3-year limit.

B. Applicability

The applicability provisions in the final rule are, except as discussed herein, essentially the same as in the proposed rules and for each of the Transport Rule trading programs.

Under the general applicability provisions of the proposed rule, the Transport Rule trading programs would cover fossil-fuel-fired boilers and combustion turbines serving—on any day starting November 15, 1990 or later—an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale, with the exception of certain cogeneration units and solid waste incineration units.

EPA requested comment on whether a more recent year should be used instead. The proposed use of the November 15, 1990 date was consistent with the use of 1990 as the beginning of the historical period for which owners and operators would generally be required to have information about their units for purposes of determining whether the units were covered by the Transport Rule trading programs. Because unit information is generally compiled and retained on a calendar year basis, EPA believes that, for the general applicability provisions, it is preferable to use January 1, rather than November 15. In determining which

[56] *See http://www.epa.gov/airmarkets/resource/docs/ejanalysis.pdf* and Ringquist, Evan J. 2011. ''Trading Equity for Efficiency in Environmental Protection? Environmental Justice Effects from the SO_2 Allowance Trading Program.'' Social Science Quarterly 92(2):297–323

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year should be used as the reference year in the general applicability provisions, EPA considers several factors.

First, in order for owners and operators, and EPA, to be able to determine which units are subject to the Transport Rule trading programs, EPA believes that the reference year should not be so far in the past that the unit information necessary to make applicability determinations is not readily available. This particularly becomes an issue in cases of older units that have changed ownership over time. EPA found, in making some applicability determinations under the CAIR trading programs, that some older units with ownership changes had difficulty obtaining information back as far as twenty or more years. Using January 1, 1990 as the reference date in the general applicability provisions could effectively require some owners and operators to retain unit information going back as far as 20 years. As a point of contrast, under the title V permitting rules, owners and operators are generally required to retain data for 5 years. *See* 40 CFR 70.6(a)(3)(B).

Second, EPA also believes that the reference year used in the applicability provisions should be far enough in the past that the unit information on which applicability determinations are based provides a full picture of the nature of the unit and its operations over time, such as the types of fuels combusted at the unit and whether the unit has produced electricity for sale.

Third, EPA considers whether selecting a different reference year for the applicability provisions than the one in the proposed rule dramatically changes what units will be covered by the Transport Rule trading programs. In this case, EPA believes, based on available information about the units potentially subject to the Transport Rule, that using a somewhat later year than the one in the proposed rule will likely have little effect on what units are covered. Balancing these factors, EPA concludes that it is reasonable to use January 1, 2005, rather than November 15, 1990, in the general applicability provisions in the final rule.

In the final rule, EPA is taking the same approach with regard to defining whether a boiler or combustion turbine is considered to be ''fossil-fuel-fired'' as the one used in the proposal. Under the proposed rule, a unit was considered to be ''fossil-fuel-fired'' if it combusts any amount of fossil fuel at any time in 1990 or later. For the same reasons that EPA decided to use January 1, 2005 in the general applicability provisions, and in order to have a consistent reference year in all applicability-related provisions, the final rule defines a ''fossil-fuel-fired'' unit as one that combusts any amount of fossil fuel in 2005 or later.

EPA notes that the final Transport Rule allows a state to submit a SIP revision (an abbreviated or full SIP) under which the state may—in addition to making certain types of changes concerning allowance allocations in the Transport Rule trading programs—expand the general applicability provisions of the Transport Rule NO_X Ozone Season Trading Program to cover fossil-fuel-fired boilers and combustion turbines serving—at any time starting January 1, 2005 or later— a generator with a nameplate capacity as low as 15 MWe producing power for sale. The exemptions, discussed below, for cogeneration units and solid waste incineration units still will continue to apply.

Cogeneration unit exemption. Under the final rule (as well as the proposed rule) certain cogeneration units or solid waste incinerators are exempt from the FIP requirements. In particular, the final rule includes an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify through each calendar year ending after the later of 2005 or that 12-month period and that meets the limitation on electricity sales to the grid. In order to meet the definition of ''cogeneration unit'' in the final rules, a unit (*i.e.,* a fossil-fuel-fired boiler or combustion turbine) must be a topping-cycle or bottoming-cycle that operates as part of a ''cogeneration system,'' which is defined as an integrated group of equipment at a source (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. A topping-cycle unit is a unit where the sequential use of energy results in production of useful power first and then, through use of reject heat from such production, in production of useful thermal energy. A bottoming-cycle unit is a unit where the sequential use of energy results in production of useful thermal energy first and then, through use of reject heat from such production, in production of useful power. In order to qualify as a cogeneration unit, a unit also must meet certain efficiency and operating standards.

In the proposed rule, a unit would have to qualify as a cogeneration unit and meet the limitation on electricity sales starting the later of 1990 or the year when the unit begins operating. EPA requested comment on whether a more recent year should be used. For the reasons discussed above concerning the reference year used in the general applicability provisions and in order to have a consistent reference year in all applicability-related provisions, EPA concludes that it is reasonable to use 2005, rather than 1990, in the cogeneration unit exemption provisions in the final rule. Consequently, the final rule provides that the requirements to qualify as a cogeneration unit and to meet the electricity sales limitation start no earlier than 2005.

In the final rule, EPA also clarifies that the electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWhr. This is consistent with the approach taken in the Acid Rain Program (40 CFR 72.7(b)(4)), where the cogeneration unit exemption originated. EPA believes that this clarification is needed to ensure that a unit serving, for example, two generators would not have a limit on sales of electricity to the grid that would be different (*i.e.,* twice as high) from the limit for a unit serving only one generator with the same total nameplate capacity as the first unit's two generators.

EPA also took comment on whether efficiency standards should be applied on a system-wide basis to bottoming-cycle units (where useful thermal energy is produced before useful power is produced), as they are for topping-cycle units (where useful thermal energy is produced after useful power) and whether to exclude, from the requirement to meet the operating and efficiency standards, calendar years during which a cogeneration unit does not operate at all. Several commenters argued EPA should apply efficiency standards to both types of units. EPA agrees that applying efficiency standards on a system-wide basis to both bottoming-cycle and topping-cycle units is reasonable because EPA sees no technical reason to distinguish between the two types of units in this instance. EPA further agrees with commenters that excluding calendar years in which the cogeneration unit does not operate at all, *i.e.,* does not combust any fuel, from the requirements to meet operating and efficiency standards is also reasonable. For such a year, the unit would not produce any useful thermal

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energy or useful power and therefore could not meet the minimum output requirements in the operating and efficiency standards, but the unit also would not have any emissions. For these reasons, the final rule expressly provides that the operating and efficiency standards do not have to be met for a calendar year throughout which a unit did not operate at all.

Solid waste incineration unit exemption. The final rule also includes an exemption for a unit that qualifies as a solid waste incineration unit during the later of 2005 or the first 12 months during which the unit first produces electricity, that continues to qualify throughout each calendar year ending after the later of 2005 or that 12-month period each year thereafter, and that meets the limitation on fossil-fuel use. In contrast, the exemption for solid waste incineration units in the proposed rule distinguished between units commencing operation before January 1, 1985 and those commencing operation on or after that date. A unit commencing operation before January 1, 1985 would be exempt if it qualified as a solid waste incineration unit starting the later of 1990 or the year when it began producing electricity and its average annual fuel consumption of non-fossil fuels exceeded 80 percent of total heat input during 1985–1987 and during any three consecutive calendar years after 1990. A unit commencing operation on or after January 1, 1985 would be exempt if it qualified as a solid waste incineration unit starting the later of 1990 or the year when it began producing electricity and its average annual fuel consumption of non-fossil fuel exceeded 80 percent of total heat input for the first 3 calendar years of operation and for any 3 consecutive calendar years thereafter.

In the proposal, EPA requested comment on whether it would be problematic to obtain sufficiently detailed information about unit operation potentially as far back as 1985–1987 and 1990, and whether the fuel consumption standard for each unit should be limited to more recent years. For the reasons discussed above concerning the reference year used in the general applicability provisions and in order to have a consistent reference year for all applicability-related provisions, EPA concludes that it is reasonable to use 2005, rather than 1990, in the solid waste incineration unit exemption in the final rule. In particular, EPA notes that the proposed provisions for units commencing operation before January 1, 1985 and for units commencing operation on or after January 1, 1985 could require some owners and operators to retain unit information going back more than 20 years before the promulgation of this final rule. Further, EPA believes that removing the distinction between units commencing operation during these two periods, and referencing somewhat later years as the earliest years for which information on fossil-fuel consumption is required, will result in the exemption still being based on sufficient data to provide a full picture of the nature and operation of the units involved. EPA also believes, based on available information about the units potentially subject to the Transport Rule, that this approach will not significantly change which units qualify for the exemption. Consequently, the final rule removes the distinction based on whether a solid waste incineration unit commences operation before January 1, 1985 or on or after January 1, 1985. In order to be exempt, the unit must qualify as a solid waste incineration unit during the later of 2005 or the first 12 months during which the unit first produces electricity, must continue to qualify throughout each calendar year ending after the later of 2005 or that 12-month period, and must meet the limitation on fossil-fuel use on a 3-year average basis during the first 3 years of operation starting no earlier than 2005 and every 3 years of operation thereafter.

Opt-in units. EPA is not finalizing the opt-in provisions that were discussed in the Transport Rule proposal. EPA proposed opt-in provisions to allow non-covered units to voluntarily opt in to any of the proposed Transport Rule trading programs and receive allocations reflecting 70 percent of the unit's emissions before opting in. These allowances were above the state-specific budgets developed under the Transport Rule to eliminate a state's significant contribution to nonattainment and interference with maintenance. In theory, an opt-in unit that makes reductions below its baseline and sells the freed-up allowances is effectively substituting its new, lower-cost reductions for higher-cost reductions otherwise required by a covered EGU, with the result that the state's significant contribution is still eliminated but at a lower total program cost.

EPA notes that theoretical benefits anticipated from allowing opt-ins did not materialize in prior trading programs with opt-in provisions. The Acid Rain Program has about 23 opt in units; the NO_X Budget Trading Program had five opt-in units; and no units opted into the CAIR programs. As a group, these opt-in units neither eased the achievement of required emission reductions in past trading programs, nor reduced overall program costs.

In the proposal, EPA requested comment on the opt-in provisions, specifically regarding: What are the benefits of and concerns about including opt-in provisions; how to ensure units are not credited for emission reductions the units would have made anyway; whether the proposed 30 percent reduction (*i.e.,* application of the 70 percent multiplier to baseline emissions) or some other percentage reduction, or no reduction, should be applied to the baseline emission rate used in determining allocations; and whether any additional percentage reduction (such as 45 percent) should be applied to SO_2 Group 1 opt-in units in Phase II to reflect the stricter limits for covered units.

Some commenters argued that increasing the Transport Rule budgets for opt-ins would undermine the goal of CAA section 110(a)(2)(D)(i)(I) to eliminate a state's significant contribution to nonattainment and interference with maintenance. One commenter stated that it does not favor allowing sources that are not subject to the emission reduction requirements to be issued allowances that would increase the overall state emission budgets, due to the uncertainty that any reductions made by such units would be surplus, verifiable, permanent and enforceable. This could compromise the integrity of the EGU emission reduction requirements of the Transport Rule and jeopardize assurance that a state's significant contribution would be eliminated, as required by the Court in *North Carolina.* Other commenters claim that, while no cheap tons are available from non-EGUs and EPA is right not to require non-EGU reductions, EPA should nonetheless allow non-EGUs to choose voluntarily to be covered by opting in.

As mentioned previously, the final Transport Rule does not include any opt-in provisions either in the FIPs or in the provisions allowing modification or replacement of the FIPs through submission of trading program provisions in SIPs. EPA has several reasons for not adopting provisions to allow opt-in units. First, as mentioned above, historically, very few units have opted in. As of 2010, 28 units out of more than 4,700 covered units (23 units out of a total of about 3,600 covered units in the Acid Rain Program and 5 units out of a total of about 2,600 covered units in the NO_X SIP Call) have opted in to EPA trading programs over the past 15 years. In the Acid Rain Program, 3 of the units opted in and

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then, effective for 2005, opted out. Four of the units opted in, immediately shut down, and continue to receive allowance allocations. Four of the units opted in and continue to operate and receive allowance allocations. Finally, 12 of the units opted in, after CAIR was finalized, in order to receive allowances usable for compliance in the CAIR SO_2 trading program. Because CAIR will be replaced by this Transport Rule, EPA anticipates that these 12 units will opt out of the Acid Rain Program. In the NO_X Budget Trading Program, 3 plants with 5 opt-in units received allocations between 2003 and 2008.

Moreover, EPA has determined that the inclusion of opt-in units in the Transport Rule trading programs would undermine the rule's objective of addressing emissions in each state that significantly contribute to nonattainment or interfere with maintenance in other states. As explained above, EPA has established budgets plus variability limits that states must meet to ensure that the significant contribution to nonattainment and interference with maintenance identified by EPA is addressed. If EPA were to allow opt-ins, and if any opt-in unit were to receive an allocation of allowances for emissions that would be reduced even if the units did not opt in, then the inclusion of that opt-in unit in the program would allow the sources covered by the Transport Rule to emit in excess of the budget plus variability limit with no new, offsetting reduction in emissions. For example, after a unit would opt in, process or fuel changes made for economic reasons (rather than due to any regulatory requirements), or installation of new emission controls or fuel-switching conducted to meet future, non-Transport Rule regulatory requirements, could result in emission reductions that would have occurred ''anyway'' (*i.e.,* even if the unit had not opted in), and the opt-in unit would be allocated allowances for the portion of its baseline emissions that would be removed by these ''anyway'' reductions. Allocations above the cap to opt-in units making ''anyway'' emission reductions would convert these reductions into extra allowances (*i.e.,* authorizations to emit) usable by covered EGUs to meet their requirements to hold allowances for emissions. Because the extra EGU emissions authorized by these extra allowances would not be offset by any new emission reductions by the opt-in units, this could threaten a state's ability to eliminate the significant contribution to nonattainment and interference with maintenance identified by EPA in the final rule. Also, opt-in units, which are allocated allowances outside the state budget for covered units, could increase the possibility that a state's total emissions would exceed the state budget plus variability and thus that the assurance provisions would be triggered.

This problem of allocating allowances for emissions that would have been reduced anyway is illustrated by the recent promulgation of the final rule, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (76 FR 15608 (March 21, 2011)) (''final Boiler MACT rule''), which requires certain industrial, commercial, and institutional boilers to meet maximum achievable control technology (MACT) standards for emissions of specified hazardous air pollutants, such as hydrogen chloride (HCL) and mercury (Hg). Some of the control technologies that can be used to meet these standards will also provide significant reductions of SO_2 emissions. For example, a boiler may use a wet scrubber or the combination of a dry sorbent injection system and a fabric filter (among other options) to meet the applicable HCL standard or may use a wet scrubber or a combination of activated carbon injection and a fabric filter (among other options) to meet the applicable Hg standard. *See* 76 FR 15614 (describing testing and compliance requirements when such controls are used to meet these standards); and Memo from Brian Shrager to Amanda Singleton and Graham Gibson, *Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial and Institutional Boilers and Process Heaters National Emissions Standards for Hazardous Air Pollutants – Major Source* (February 11, 2011), Document ID EPA–HQ–OAR–2009–0491–4036 (section 3.1, describing control options for HCL and Hg control). In fact, EPA estimated that the new standards would result in emission reductions of not only the hazardous air pollutants directly subject to the standards, but also in other air pollutants such as SO_2. Specifically, EPA projected that compliance with the final Boiler MACT rule standards will result in about 431,000 tons of annual SO_2 reductions from existing boilers subject to the final Boiler MACT rule. This will comprise on average about a 46 percent reduction in SO_2 emissions for this group of boilers. Coal- and oil-fired boilers—which are the boilers likely to have the most uncontrolled SO_2 emissions and so would be the most likely types of units to consider opting into the Transport Rule trading programs if opting-in were allowed—are projected to reduce about 409,000 tons of annual SO_2 as a result of complying with the final Boiler MACT rule, or about a 50 percent reduction in SO_2 emissions. *See* Memo from Brian Shrager to Amanda Singleton and Graham Gibson, Appendix B–1, (where column CE represents baseline SO_2 emissions and column CH represents SO_2 reductions resulting from the final Boiler MACT rule compliance). The amount of offsetting SO_2 increases projected to result from final Boiler MACT rule compliance, *e.g.,* from additional fuel being combusted to generate electricity to operate emission controls, is minor. *See* 76 FR 15651 (Table 4) and 15653 (showing projected total SO_2 reductions for all boilers and process heaters of about 442,000 tons and net SO_2 reductions of about 440,000 tons).

Consequently, a boiler subject to the final Boiler MACT rule may install a wet acid gas scrubber or a bag house in order to meet the HCL or Hg standard applicable to boilers under the final Boiler MACT rule and thereby achieve SO_2 emission reductions. If that boiler were to opt in to one of the Transport Rule SO_2 trading programs during the year before installing these controls to comply with the final Boiler MACT rule, then the boiler would be allocated allowances for the unit's current tons of SO_2 emissions and would not need to use these allowances for compliance under the Transport Rule once the final Boiler MACT-related controls were installed. The allowances allocated to the boiler would be additional allowances above the Transport Rule trading budget for the state where the boiler was located. As a result, the boiler would have freed-up allowances above the state trading budget that represent reductions that the boiler would have made anyway (*i.e.,* even if the boiler had not opted in) and that could be sold to EGUs covered by the Transport Rule. In effect, the opting-in of the boiler would result in the conversion of the boiler's SO_2 reductions from the final Boiler MACT rule into increased emissions above the state trading budget from EGUs subject to the Transport Rule.

Commenters addressed this issue. For instance, one commenter suggested that SO_2 reductions made by a boiler under the final Boiler MACT rule should be eligible for opt-in provision allowances under the Transport Rule trading programs. Another commenter stated that, given the uncertainty that reductions made by opt-in units would be surplus, verifiable, permanent, and enforceable, opt-in provisions could

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compromise the integrity of the EGU emission reductions.

For the reasons explained above, EPA agrees with the latter commenter. Further, EPA notes that none of the commenters supporting adoption of the opt-in provisions suggested any revision to the proposed opt-in provisions that would address this problem. While the proposed opt-in provisions would limit an opt-in unit's allocation for a control period by calculating the allocation using the lesser of the unit's pre-opt-in SO_2 emission rate or the most stringent SO_2 emission rate applicable in that control period, this would not address SO_2 rate reductions that are not directly required by the final Boiler MACT rule but that are a secondary result of using and operating certain emission controls installed to comply with the HCL or Hg standards under the final Boiler MACT rule. Because the secondary SO_2 reductions will vary depending on the type of controls installed and on the extent to which the controls are used, and a boiler may use a combination of emission controls and other approaches to reduce HCL or Hg emissions (such as fuel switching), EPA believes that it is highly unlikely that opt-in provisions could prevent allocation for ''anyway'' emission reductions resulting from compliance with the final Boiler MACT rule. EPA therefore believes that the final Boiler MACT rule provides a concrete example of why adoption of opt-in provisions could undermine the rule's objective of addressing emissions in each state that significantly contribute to nonattainment or interfere with maintenance in other states. EPA notes that the final Boiler MACT rule, of course, is simply one example of how allocations for ''anyway'' reductions could occur and undermine the statutory requirements of the Transport Rule.

C. Compliance Deadlines

1. Alignment With NAAQS Attainment Deadlines

The compliance dates in the final Transport Rule are aligned with the attainment deadlines for the relevant NAAQS and consistent with the charges given to EPA by the Court in *North Carolina.* EPA proposed to require, and the final rule requires, compliance by 2014 with an initial phase of reductions in 2012.[57] Sources are required to comply with annual SO_2 and NO_X requirements by January 1, 2012 and January 1, 2014 for the first and second phases, respectively. Similarly, sources are required to comply with ozone-season NO_X requirements by May 1, 2012, and by May 1, 2014. In selecting these dates, EPA was mindful of the NAAQS attainment deadlines which require reductions as expeditiously as practicable and no later than specified dates (see 42 U.S.C. 7502(a)(2)(A) (general attainment dates); 42 U.S.C. 7511(a)(1) (attainment dates for ozone nonattainment areas)), and also mindful of the court's instruction to ''decide what date, whether 2015 or earlier, is as expeditious as practicable for states to eliminate their significant contributions to downwind nonattainment.'' *North Carolina,* 531 F.3d at 930.

1997 $PM_{2.5}$ NAAQS Attainment Deadlines. For all areas designated as nonattainment with respect to the 1997 $PM_{2.5}$ NAAQS, the deadline for attaining that standard is as expeditious as practicable but no later than April 2010 (5 years after designation), with a possible extension to no later than April 2015 (10 years after designation).[58] Many areas have already come into attainment by the April 2010 deadline due in part to reductions achieved under CAIR. The fact that the 2010 deadline will have passed before the Transport Rule is finalized emphasizes the importance of obtaining reductions as expeditiously as practicable. In addition, reductions achieved in upwind states by the 2014 emissions year will help downwind states demonstrate attainment by the April 2015 deadline.

2006 $PM_{2.5}$ NAAQS Attainment Deadlines. For all areas designated as nonattainment with respect to the 2006 24-hour $PM_{2.5}$ NAAQS, the attainment deadline must be as expeditious as practicable but no later than December 2014. Areas that fail to meet that deadline can request an extension to as late as December 2019.

Upwind emission reductions achieved by the 2014 emissions year will help meet the December 2014 attainment deadline. In addition, the first phase of reductions in 2012 will help many areas attain in a more expeditious manner.

Further, a deadline of January 1, 2014 also provides adequate and reasonable time for sources to plan for compliance with the Transport Rule and install any necessary controls. EPA believes that this deadline is as expeditious as practicable for the installation of the controls, if any, needed for compliance with the 2014 state emission budgets. (*See* further discussion in section V.C.2.)

1997 Ozone NAAQS Attainment Deadlines. Ozone nonattainment areas must attain permissible levels of ozone ''as expeditiously as practicable,'' but no later than the date assigned by EPA in the ozone implementation rule. 40 CFR 51.903. The areas designated nonattainment in 2004 with respect to the 1997 8-hour ozone NAAQS in the eastern United States were assigned maximum attainment dates effectively corresponding to the end of the 2006, 2009, and 2012 ozone seasons. The maximum attainment deadlines for the 1997 standard run from the June 15, 2004 effective date of designation for that standard. The time periods are based on the time periods provided for these classifications in section 181 of the Act, 45 U.S.C. 7511(a). However, instead of running from the 1990 date of enactment of the CAA as specified in section 181, our regulation provides that they run from the date of designation. An area's maximum attainment date is based on its nonattainment classification—that is, whether it is classified as a marginal, moderate, serious, severe, or extreme ozone nonattainment area. Marginal areas have three years from designation to attain the standard. Moderate, serious, severe, and extreme areas have 6, 9, 15, and 20 years, respectively. The maximum attainment deadlines associated with the 1997 ozone standards are June 15, 2007 for marginal areas, June 15, 2010 for moderate areas, and June 15, 2013 for serious areas. Because the actual deadline occurs in the middle of an ozone season, data from that ozone season is not considered when determining whether the area has attained by the deadline. Thus, these maximum attainment deadline dates effectively correspond with the end of the 2006, 2009, and 2012 ozone seasons. Reductions achieved or air quality improvements realized after those dates will not help the areas meet their maximum attainment deadlines.

Many areas have already attained the standard due in part to CAIR, federal

[57] For the annual programs, sources are required to have, by March 1, 2013, sufficient allowances in their accounts to cover their 2012 emissions. For the ozone-season program, they must have allowances in their accounts by December 1, 2012 to cover 2012 ozone-season emissions. The state budgets which determine the number of allowances allocated to units in each state become more stringent for some states in 2014.

[58] Section 172(a)(2) of the Clean Air Act provides that the attainment dates for areas designated nonattainment with a NAAQS shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date of designation. This section also allows the Administrator to extend the attainment date to the extent she determines appropriate, for a period no greater than 10 years from the date of designation as nonattainment, considering the severity of nonattainment and the availability and feasibility of pollution control measures. Designations for the 1997 $PM_{2.5}$ NAAQS became effective on April 5, 2005. Designations for the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 14, 2009.

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mobile source standards, and other local, state, and federal measures. Other areas, however, have been reclassified to a higher classification either because they failed to attain by their attainment date or because the state requested reclassification to avoid missing an attainment date. Those that have not yet attained the standard now have maximum attainment dates ranging from June 2011 (these are the moderate areas that have been granted a 1-year extension due to clean data for the 2009 ozone season) to June 2024. The areas classified as ''serious'' nonattainment areas have a June 2013 maximum attainment deadline. Areas that missed their earlier deadlines and have been reclassified as ''severe'' or ''extreme'' nonattainment areas now have maximum nonattainment deadlines of June 2019 and June 2024 respectively. As explained above, an area with a June 2013 deadline would need to attain based on ozone data from the 2010–2012 ozone seasons, an area with a June 2019 deadline would need to attain based on ozone data from the 2016–2018 ozone seasons, and an area with a June 2024 deadline would need to attain based on ozone data from the 2021–2023 ozone seasons.

The Transport Rule's first phase of reductions in 2012 will help the remaining areas with June 2013 maximum attainment deadlines attain the 1997 8-hour ozone NAAQS by their deadline. If EPA determines that an area failed to attain by the 2013 deadline, the area would be reclassified to severe and would be subject to the more stringent emission control requirements that apply to the severe classification. The reductions will also help areas with later deadlines attain as expeditiously as practicable and improve air quality in those areas.

2012 Interim Compliance Deadline. EPA is requiring an initial phase of reductions starting in 2012. These reductions are necessary to ensure that significant contribution to nonattainment and interference with maintenance are eliminated as expeditiously as practicable and in time to help states meet their attainment deadlines. As the court emphasized in *North Carolina*, the significant contribution to nonattainment and interference with maintenance from upwind states must be eliminated as expeditiously as practicable to help downwind states to achieve attainment as expeditiously as practicable as required by the CAA. Further, reductions are needed by 2012 to help states attain before the June 2013 maximum attainment date for ''serious'' ozone nonattainment areas, to ensure states attain as soon after the original April 2010 attainment deadline for the 1997 $PM_{2.5}$ NAAQS, and to help states attain before the December 2014 attainment deadline for the 2006 $PM_{2.5}$ NAAQS.

In addition, because this final rule will replace CAIR, EPA could not assume that after this rule is finalized, EGUs would continue to emit at the reduced emission levels achieved by CAIR. Instead, it is the emission reduction requirements in the proposed FIPs that will determine the level of EGU emissions in the eastern United States. For this reason also, EPA concludes that it is appropriate to require an initial phase of reductions by 2012 to ensure that existing and planned SO_2 and NO_X controls operate as anticipated.

Addressing the Court's Concern about Timing. As directed by the Court in *North Carolina*, 531 F.3d 896, and as described previously, EPA established the compliance deadlines in the Transport Rule based on the respective NAAQS attainment requirements and deadlines applicable to the downwind nonattainment and maintenance sites.

The 2012 deadline for compliance with the limits on ozone-season NO_X emissions is necessary to ensure that states with June 2013 maximum attainment deadlines get the assistance needed from upwind states to meet those deadlines. The 2012 deadline for compliance with the limits on annual NO_X and annual SO_2 emissions is necessary to ensure attainment as expeditiously as practicable in areas which failed to attain by the 2010 attainment deadline for the 1997 $PM_{2.5}$ NAAQS and had to request an extension to 2015.

Similarly, the 2014 deadline for compliance with the limits on annual NO_X and annual SO_2 emissions is necessary to ensure that downwind states get the benefit of upwind reductions prior to the December 2014 maximum attainment deadline for the 2006 $PM_{2.5}$ NAAQS. It is also necessary to ensure reductions occur in time to assist with attainment in downwind areas that received the maximum 5-year extension of the 5-year attainment deadline for the 1997 $PM_{2.5}$ NAAQS (taking into account the need for reductions by 2014 to demonstrate attainment by April 2015).

The 2012 compliance deadline for the first-phase of annual NO_X and annual SO_2 emission reductions will assure the reductions are achieved as expeditiously as practicable. A significant amount of the emissions identified as significantly contributing to nonattainment or interfering with maintenance in other states can be eliminated by 2012. EPA believes it is appropriate to do so in light of the court's direction to EPA to ensure states eliminate such emissions as expeditiously as practicable. *North Carolina* 531, F.3d at 930. Given the time needed to design and construct scrubbers at a large number of facilities, EPA believes the 2014 compliance date is as expeditious as practicable for the full quantity of SO_2 reductions necessary to fully address the significant contribution to nonattainment and interference with maintenance. Requiring reductions in transported pollution as expeditiously as practicable, as well as within maximum deadlines, helps to promote attainment as expeditiously as practicable. This is consistent with statutory provisions that require states to adopt SIPs that provide for attainment as expeditiously as practicable and within the applicable maximum deadlines.

b. Public Comments and EPA Responses

EPA received numerous comments on the proposed compliance dates. A number of commenters supported EPA's compliance schedule and rationale. Other commenters supported extending the compliance deadlines to later dates.

Many commenters questioned the technical feasibility of achieving the required reductions by the 2012 and 2014 dates. EPA's responses to those comments are discussed below in section VII.C.2.

Other commenters provided policy and legal arguments for allowing states to develop SIP alternatives to the FIP, and to build time for that SIP development and review process into the compliance schedule. For example, some commenters asserted that the requirement in the CAA for providing reductions ''as expeditiously as practicable'' must be balanced with CAA provisions allowing states to develop state implementation plans prior to EPA imposing FIPs. EPA responses to those comments are discussed in section X.

Some commenters suggested that EPA had the ability to leave CAIR in place for a transition period, and by doing this EPA could allow for a longer compliance period for this rule. EPA does not believe it would be appropriate, in light of the Court's decision in *North Carolina*, to establish a lengthy transition period to the rule that will replace CAIR. Although the Court decided on rehearing to remand CAIR without vacatur, the Court stressed its prior decision that CAIR was deeply flawed and EPA's obligation to remedy those flaws. *North Carolina*, 550

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F.3d 1176. Although the Court did not set a definitive deadline for corrective action, the Court took care to note that the effectiveness of its opinion would not be delayed "indefinitely" and that petitioners could bring a mandamus petition if EPA were to fail to modify CAIR in a manner consistent with its prior opinion. *Id.* Given the Court's emphasis on remedying CAIR's flaws expeditiously, EPA does not believe it would be appropriate to establish a lengthy transition period to the rule which is to replace CAIR.

As relates to $PM_{2.5}$, EPA received a number of comments on its proposal to include a 2012 deadline to ensure that emission reductions needed to reduce $PM_{2.5}$ be achieved "as expeditiously as practicable." Some commenters supported EPA's 2012 deadline. Other commenters believed that it was unnecessary and unwarranted for EPA to impose emission reduction requirements in advance of the 2014 attainment date. In light of the 2014 five-year attainment date for the 2006 $PM_{2.5}$ NAAQS (with a possible extension to 2019), and the possible extension to April 2015 for the 1997 $PM_{2.5}$ NAAQS, these commenters believed EPA's 2012 emission reduction requirements for annual $PM_{2.5}$ and NO_X were not necessary. EPA disagrees with these commenters, for a number of reasons. First, EPA notes (supported by commenters) that there is a clear statutory obligation to attain "as expeditiously as practicable." Second, EPA notes that there are feasible reductions available by 2012. Third, EPA believes that the substantial health and environmental benefits achieved by the rule underscore the importance of achieving the reductions as soon as possible.

With respect to ozone, some commenters noted that the proposed rule required ozone reductions by 2012 for states impacting areas which EPA's analysis shows will attain the 1997 ozone NAAQS by 2014 without further controls. Those commenters questioned the importance of getting reductions in such states and whether the 2012 deadline is necessary. EPA disagrees with those comments. Except for Houston, all ozone areas within the region addressed by this rule have attainment dates no later than 2013. In effect, this means that emission reductions needed to attain the 1997 ozone NAAQS must be in place by the 2012 ozone season. EPA believes that if there are reductions available by 2012, and those emission reductions have in fact been identified, it is appropriate and necessary to ensure that those reductions are in place.

2. Compliance and Deployment of Pollution Control Technologies

The power industry will undertake a diverse set of actions to comply with the Transport Rule at the start of 2012 and another set of actions when companies in Group 1 states comply with more stringent SO_2 budgets at the start of 2014. In 2012, the industry will largely meet the rule's NO_X requirements by: Operating an extensive existing set of combustion and post-combustion controls on fossil fuel-fired generators; dispatching lower emitting units more often; and installing and operating a limited amount of relatively simple NO_X pollution controls in states not previously subject to CAIR. For the SO_2 requirements, EPA anticipates at a minimum that coal-fired generators will operate the substantial capacity of advanced pollution controls already in place or scheduled for 2012 use; some units will also elect to burn lower-sulfur coals; and the fleet will increase dispatch from lower-sulfur-emitting units as well as from natural gas-fired generators. EPA provides a more detailed explanation below of how fuel switching to lower sulfur coals factored in to the design of the final Transport Rule.

By 2014, EPA's budgets under the Transport Rule will sustain previous NO_X and SO_2 reductions as well as account for reductions from additional advanced NO_X and SO_2 controls that are driven by other state and federal requirements. In addition to these reductions, companies in Group 1 states are also projected to add a limited amount of advanced SO_2 controls in 2014 that will be discussed below.

EPA's expectations are supported by the IPM analysis reported in this rule's RIA (see Chapter 7). Notably, since EPA has established a cap and trade control system for lowering NO_X and SO_2 emissions, individual owners and operators of covered units have some flexibility in meeting the program's requirements as needed and are free to find alternative ways to comply. The RIA clearly shows a viable known pathway for owners and operators to comply at reasonable costs, although it is not the only compliance pathway possible under this flexible regulation that could deliver the emission reductions required under the rule. Notably, by 2014 and beyond, the power industry may also augment the projected compliance efforts with programs aimed at improving energy efficiency.

Table VII.C.2–1—shows EPA's projection of the amount of existing coal-fired generating capacity in gigawatts (GW) that may retrofit various systems for compliance with this rule.

TABLE VII.C.2–1—PROJECTED POTENTIAL AIR POLLUTION CONTROL (APC) RETROFITS FOR TRANSPORT RULE [59]

Capacity retrofitted by	Wet FGD	Dry FGD	DSI	SCR	LNB/OFA improvements
January 1, 2012	....	....	....	....	10 GW
January 1, 2014	5.7 GW	0.2 GW	3.0 GW	0 GW.	

EPA received proposal comments expressing a concern about the feasibility of deploying retrofit air pollution control (APC) technologies in the time frames available between the final date of this rule and the compliance dates. As discussed below, EPA believes that it is feasible for the electric power sector and its APC supply chain to either make most of the projected retrofits in time to meet the 2012 and 2014 compliance deadlines, or to comply by other means.

a. 2012 Power Industry Compliance

EPA's analysis of emission reductions available in 2012 assumes year-round operation of existing post-combustion pollution controls in states covered for $PM_{2.5}$ and ozone-season operation of NO_X post-combustion controls in states covered for ozone. EPA also modeled emission reductions available in 2012 at the \$500/ton threshold for SO_2, \$500/ton for annual NO_X, and \$500/ton for ozone-season NO_X.

For SO_2, EPA believes that reductions associated with the following methods of control are available and will be used

[59] GW: Gigawatts of capacity retrofitted; FGD: Flue gas desulfurization (SO_2 control); DSI: Dry sorbent injection (SO_2 control); SCR: Selective catalytic reduction (NO_X control); LNB/OFA: Low-NO_X burner and/or overfire air (NO_X controls).

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as compliance strategies to meet the 2012/2013 budgets: (1) Operation of existing controls year-round in $PM_{2.5}$ states, (2) operation of scrubbers that are currently scheduled to come online by 2012, (3) some sources switching to lower-sulfur coal (see section VII.C.2.c that follows), and (4) changes in dispatch and generation shifting from higher emitting units to lower emitting units. EPA modeling and selection of a $500/ton cost threshold includes all existing and planned controls operating year round (items 1 and 2). It also reflects an amount of coal switching and generation shifting that can be achieved for $500/ton. This set of expected actions was confirmed in the detailed modeling of EPA's final remedy in the RIA and can be reviewed there.

The power sector is already strongly positioned to achieve the Transport Rule state budgets presented in section VI.D through at least three distinct strategies. First, the sector will optimize its use of the large proportions of advanced pollution controls already present throughout the fleet. Second, the sector will take advantage of the substantial new pollution control technology that is already on the way for deployment by 2012. Third, the remainder of the fleet will flexibly adopt the most economic low-emitting fuel mix available at each unit to deliver cost-effective emission reductions complementing the reductions achieved from optimized use of the fleet's pollution control technology. The state maps in Chapter 7 of this rule's Regulatory Impact Analysis demonstrate how these emission reduction strategies for 2012 will build off of the sector's historic trend toward cleaner generation profiles. Also, the detailed unit-level projection files from EPA's IPM power sector modeling of the Transport Rule remedy (found in the docket for this rulemaking) show how EGUs adopt these strategies to not only reach the 2012 budgets, but in fact in many states overcomply with the budgets and build up a bank of allowances under the programs for future flexibility.

The following paragraphs illustrate the degree to which the existing fleet is already prepared to adopt these emission reductions in 2012 in order to attain the required emission reductions for SO_2, annual NO_X, and ozone-season NO_X under the Transport Rule. More specifically, the illustrative paragraphs demonstrate emission reduction pathways for coal capacity to optimize or increase operation of existing control technology, timely implement existing plans to bring additional control technology on line, and to cost-effectively make use of lower-emitting fuel alternatives.

Of the 240 GW of coal capacity in the Transport Rule region covered for fine particles, approximately 110 GW—more than 45 percent—had existing advanced pollution control for SO_2 already in place in 2010, including scrubbers (FGD), dry sorbent injection (DSI), or circulating fluidized bed boilers. Of this controlled coal capacity, EPA expects a significant portion will improve emission rates through either increased use of control technology and/or additional fuel switching. EPA notes that an additional 39 GW of advanced SO_2 controls in the region are scheduled to come online over the 2010–2012 timeframe and will also assist in meeting 2012 emission reduction requirements. Thus, by 2012 more than half of affected coal capacity—152 GW—will be operating with advanced SO_2 control equipment. Additionally, EPA expects approximately 40 GW of uncontrolled coal capacity in the region to take advantage of the existing coal supply infrastructure, possibly switching coal use or coal blending behaviors to make cost-effective reductions in SO_2 emission rates where economic to respond to the Transport Rule 2012 emission reduction requirements.

EPA notes that approximately 136 GW of the 240 GW—more than 56 percent—of coal capacity in the Transport Rule region covered for fine particles had existing advanced pollution control for NO_X already in place in 2010, including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or circulating fluidized bed boilers. Of this capacity, EPA anticipates a significant portion will improve their NO_X emission rate through increased operation of these existing controls. Additionally, EPA notes that an additional 21 GW of SCR and 4 GW of enhanced combustion controls (including low-NO_X burners and overfire air) are scheduled to come online in the region during the 2010–2012 timeframe, bringing the total region's coal capacity operating with NO_X emission reduction technology to 158 GW (more than 65 percent of total coal capacity in the Transport Rule fine particle region). EPA also projects that approximately 13 GW of coal capacity will make some reduction in their NO_X emission rates by enhancing performance of existing combustion controls or SNCR, or by fuel switching.

In the Transport Rule states covered under the ozone-season program, approximately 145 GW of the 260 GW (more than 55 percent) of coal capacity had existing NO_X control technology in place in 2010. EPA expects a significant portion of that capacity to achieve emission reductions during the 2012 ozone-season through improved operation of SCR. Additionally, in the Transport Rule ozone region there will be approximately 21 GW of additional advanced NO_X control installations and 7 GW of additional combustion control improvements or installations coming online during the 2010 to 2012 time frame. EPA projects that 17 GW of coal capacity in the Transport Rule ozone region will reduce NO_X emission rates by enhancing performance of existing combustion controls or SNCR or by fuel switching.

For NO_X, EPA has also concluded that it is appropriate to require reductions through a limited amount of combustion control improvements, and in some cases, retrofits such as low-NO_X burners (LNB) and/or overfire air (OFA). EPA recognizes that the 6-month time frame between rule finalization and start of the first compliance period would not allow for the installation of a major post-combustion NO_X control such as SCR. Assumed improvements and retrofits for the January 1, 2012 deadline for annual NO_X reductions therefore only involve the much simpler LNB/OFA control modifications or installations. Alternatively, some plant owners might choose to achieve NO_X reductions in a similar time period through an even simpler retrofit—SNCR.[60]

Although the improvements, and in some cases, installation of combustion controls would be an economic means of achieving emission reductions, these specific controls are not required for compliance purposes under the final Transport Rule remedy. Individual sources may comply through other measures (such as purchasing additional allowances) in the event that it takes more than 6 months for installation of a given combustion control. The vast majority of covered sources already have combustion controls installed; therefore, the NO_X reductions associated with these incremental control improvements and installations are small.

[60] David L. Wojichowski, SNCR System—Design, Installation, and Operating Experience *http://www.netl.doe.gov/publications/proceedings/02/scr-sncr/wojichowski-1.pdf.*

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Based on the Transport Rule's geography, EPA estimates that approximately 10 GW of coal-fired units may improve, and in some cases, install LNB/OFA specifically in reaction to the Transport Rule NO_X caps. EPA reflects the effects of these installations in the 2012 annual and ozone-season NO_X budgets, which would yield reductions of approximately 28,000 tons of annual NO_X and 14,000 tons of ozone-season NO_X. EPA assumes these controls are cost effective at $500/ton and that they should be incentivized through budgets given the 2013 attainment deadline for ozone areas classified as ''serious.'' Once installed, LNB/OFA operates any time the boiler is fired and thus yields NO_X reductions beyond the ozone season alone.

In the proposal's LNB technical support document,[61] EPA observes that LNB and/or OFA installations, burner modifications, or other NO_X reduction controls would likely have to be installed during fall 2011 or spring 2012 outages in order to achieve significant reductions for 2012. While this 6-month schedule is aggressive, industry has shown that it can be met. For example, Limestone Electric Generating Station Unit 2, an 820 MW tangentially-fired lignite unit, was retrofitted with Foster Wheeler's Tangential Low NO_X (TLN3) system in less than six months, including engineering, fabrication, delivery and installation.[62] Harlee Branch Unit 4, a 535 MW cell-fired unit, was retrofitted with Riley Power's low-NO_X Dual Air Zone CCV burners on a similar schedule.[63] These are tangentially-fired and wall-fired units, respectively, representative of the unit types that might make LNB/OFA improvements for compliance with this rule. Although such 6-month schedules can be achieved on some units, under favorable circumstances, historical projects suggest a more typical schedule would be 12 to 16 months for the contractor's portion of the work.[64] A plant owner's project planning and procurement work in advance of a contract award would typically involve several additional months. On the other hand, there are other approaches that can also be implemented in a short time frame to achieve significant NO_X reduction. As mentioned above, relatively simple SNCR systems can be installed quickly; and the re-tuning or upgrading of existing combustion control systems can often provide significant NO_X reductions and can be performed quickly.[65]

As stated above, EPA believes that LNB/OFA modifications or retrofits would be possible during the 6-month interim between rule signature and the start of the first compliance period, particularly for those ''early movers'' who have initiated LNB projects based on the proposed rule. However, as shown in Table VII.C.2–2, below, even if all LNB modifications or installations are delayed until the beginning of the 2012 ozone season, the reductions only represent 1 percent of most covered states' annual NO_X budgets, and no more than 11 percent of any affected state's annual NO_X budget. Under such a scenario, these delayed reductions would still be well within the 18 percent variability limit applied to each state's annual NO_X budget. In light of this limited consequence and the supporting material above, EPA includes LNB-driven NO_X reductions in both annual and ozone-season NO_X budgets for 2012.

TABLE VII.C.2–2—EARLIEST REDUCTIONS ASSUMED FROM LNB INSTALLATIONS IN THE TRANSPORT RULE STATES SUBJECT TO THE ANNUAL NO_X PROGRAM *

	NO_X reductions from LNB operation from January–April (tons)	Annual NO_X state budget (tons)	Percent of budget met by earliest LNB reductions (percent)
Georgia	646	62,010	1
Iowa	567	38,335	1
Kansas	2,131	30,714	7
Minnesota	2,303	29,572	8
Nebraska	3,008	26,440	11
Region-wide Total	8,656	1,245,869	1

* Based on EPA IPM Analysis of Final Transport Rule.

b. 2014 Power Industry Compliance

EPA projects that compliance with 2014 requirements for NO_X will result largely from operation of existing and future controls required by state and other federal requirements, as well as the appropriate dispatch of the electric generation fleet. EPA does not project additional NO_X pollution control retrofits aside from about 10 GWs of combustion control improvements or retrofits projected for the 2012 compliance period. To comply with the rule's SO_2 requirements, EPA projects that the power industry will rely on existing controls, operate newly installed advanced controls necessary for other binding state and federal requirements, rely more on relatively lower sulfur coals, and dispatch lower-emitting generation units. In Group 1 states, industry is projected to increase switching to lower sulfur coals and install a limited amount of additional scrubbers and other advanced pollution control technology. EPA's assessment of the industry's ability to install SO_2 pollution controls in 2014 and undertake the projected coal switching follows below.

EPA's modeling of least-cost compliance with the state budgets under the Transport Rule projects approximately 5.9 GW of FGD systems and lesser amounts of other technologies will be retrofitted by 2014

[61] Technical Support Document (TSD) for the Transport Rule, Docket ID No. EPA–HQ–OAR–2009–0491, Installation Timing for Low NO_X Burners (LNB).

[62] R. Pearce, J. Grusha, Reliant Energy Tangential Low NO_X System at Limestone Unit 2 Cuts Texas Lignite, PRB and Pet Coke NO_X, *http://www.fwc.com/publications/tech_papers/files/tp_firsys_01_02.pdf.*

[63] B. Courtemanche, *et al.,* Reducing NO_X Emissions and Commissioning Time on Southern Company Coal Fired Boilers With Low NO_X Burners and CFD Analysis, *http://www.babcockpower.com/pdf/t-182.pdf.*

[64] M. O'Donnell, Babcock & Wilcox Company, (personal communication with EPA staff, February 22, 2011).

[65] N.C Widmer, et al., Coal Power, October 8, 2009, *http://www.coalpowermag.com/ops_and_maintenance/Zonal-Combustion-Tuning-Systems-Improve-Coal-Fired-Boiler-Performance_226.html.*

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for compliance with the Transport Rule.[66] [67] EPA's schedule assumptions for these larger more complex projects were developed in an earlier study and mentioned in the proposal: 27 months for retrofitted wet FGD and 21 months for SCR.[68] Note that a dry FGD system, due to its relatively simpler configuration and lesser cost, would typically take somewhat less time to retrofit than wet FGD.

As discussed below, EPA believes that its schedule assumptions remain reasonable expectations for sources that have completed most of their preliminary project planning and can quickly make commitments to proceed. These schedules do not include the extensive time that some plant owners might spend in making a decision on whether or not to retrofit. They do include the time needed to make a final confirmation of the type of technology to be used at a particular site, to prepare bid requests, award contracts, perform engineering, obtain construction and operating permits (in parallel with project activities), perform construction, tie-in to the existing plant systems, and perform integrated systems testing.

EPA received comments on the proposed rule indicating that some past single-unit APC retrofits had considerably longer schedules, with a few exceeding 48 months. EPA engineering staff have extensive experience with power plant and APC system design, construction, and operation. Based on that experience, EPA can observe that in the absence of a compelling deadline or major economic incentive, many large project schedules are considerably longer than necessary. Given further observations as explained below, EPA believes it is reasonable to expect that almost all future APC retrofits can be completed far more quickly than they were in recent history. EPA's perspective on this matter derives in part from a comparison of longer APC schedules (as provided by some commenters) to the project schedule for an entire new coal-fired unit, including its APC systems. Springerville Unit 3, for example, is a new 400 MW subbituminous coal-fired unit with SCR and dry FGD that became operational in July 2006, some 33 months after the turnkey engineering-construction contractor was given a notice to proceed with engineering.[69] Springerville was clearly on an accelerated schedule, as its original planned schedule was about 38 months. Another example is Dallman Unit 4, a high-sulfur bituminous coal-fired 200 MW unit with SCR, fabric filter, wet FGD, and wet ESP. Dallman Unit 4 was first synchronized in May 2009, several months ahead of schedule, and about 36 months after its turnkey contractor placed initial major equipment orders.[70] The main point here is that recent APC project schedules, and those of large complex power projects, can be significantly accelerated. Because the scope and complexity of the work involved for an entire new coal unit and its APC systems is perhaps five times greater than that of a retrofit wet FGD system alone, EPA believes it is reasonable to expect that even the most complex retrofit APC project can be significantly accelerated as well. Additional factors are discussed below that further support the feasibility of installing by 2014 the 5.9 GW of FGD retrofits projected for this rule.

Although IPM modeling provides reliable estimates on a regional basis, and cannot be as accurate at the level of individual plants or units, it is informative and relevant to consider IPM's plant level projections in this case. Although the IPM-projected retrofits named below may not actually occur, IPM projects that they would be economic and would allow industry to meet the tighter SO_2 emission standards in Group 1 states in 2014. EPA notes that the owners of the particular plants mentioned below (Duke Energy, AEP, Edison International) are large, experienced, versatile utilities that have done considerable advance planning and should also have above-average flexibility to comply with state budgets across their fleets. EPA would expect such owners to have relatively little difficulty in permitting and financing FGD retrofits.

Of the Transport Rule-related FGD retrofits, 0.2 GW is projected to use dry FGD, which EPA expects to be simpler and quicker to install than wet FGD. Half of the 5.9 GW (Muskingum, Rockport) has already been committed under consent decrees to add controls or retire; [71] and EPA reasonably believes that significant preliminary project planning work has already been done for those projects. An additional 1,200 MW (Homer City) had completed project planning and was ready to proceed in 2007, before putting the project on hold.[72] The latter plant is now facing EPA legal action and the possibility of a required expeditious FGD retrofit.[73] Thus, of the 5.9 GW of projected FGD retrofits resulting from this rule, nearly 75 percent appears to be in good position for an early start of construction, and over 3 GW of that would be bringing forward already committed compliance start dates.

Any of the above mentioned potential retrofits or any other unit that might choose to retrofit FGD for a January 2014 compliance date will likely have to use various methods to accelerate the project schedule. Such methods could include the use of parallel permitting, overtime and/or two-shift work schedules during construction, and 5- or 6-day work weeks instead of the 4-day × 10-hour schedules often used to minimize cost when time is not of the essence. Increased use of offsite modularization and pre-fabrication of APC components could also shorten schedules and reduce job hours.

EPA believes that the January 1, 2014 compliance date is as expeditious as practicable for the sources installing large, complex control systems. The following additional observations support EPA's expectation that the limited 5.9 GW of FGD retrofits can be realized in the 30 month interim between rule signature and the start of 2014:

- There are documented instances of large, complex wet FGD retrofits being deployed in less than 30-months (excluding the time for owners' project

[66] Nearly all of the 5.9 GW of FGD retrofits are comprised by some 12 units at 7 plants (Beckjord, Muskingum River, Homer City, Rockport, Kammer, Danskammer, and Will County).

[67] As noted elsewhere in this preamble, the projected impacts of this final rule presented in the preamble do not reflect minor technical corrections to SO_2 budgets in three states (KY, MI, and NY) and assumed preliminary variability limits that were smaller than the variability limits finalized in this rule. EPA conducted sensitivity analysis factoring in these corrections; the results of this analysis include a small increase of about 700 MW of additional wet FGD retrofit projected for 2014. This projected additional retrofitting capacity is already required to retrofit under a consent decree and should therefore have already conducted advanced retrofit planning. EPA therefore believes that this incremental projected retrofit behavior (factoring in the technical corrections made after the main impact analyses were conducted) is feasible by 2014 for the same reasons presented in this section regarding the projected retrofit behavior from the main analysis of the final rule.

[68] EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies; EPA–600/R–02/073 October 2002.

[69] Best Coal-fired Projects, Springerville Unit 3 Expansion Project, Power Engineering, November 2006, *http://www.powergenworldwide.com/index/display/articledisplay/282547/articles/power-engineering/volume-111/issue-1/features/projects-of-the-year.html.*

[70] *http://www.cwlp.com/electric_division/generation/Dallman%204%20Power%20Plant%20of%20the%20Year.pdf.*

[71] *http://www.epa.gov/compliance/resources/decrees/civil/caa/americanelectricpower-cd.pdf.*

[72] *http://www.businesswire.com/news/home/20060731005193/en/Contractors-Selected-Install-Emissions-Control-System-Pennsylvania.*

[73] *http://www.epa.gov/Compliance/resources/complaints/civil/caa/homercity-cp.pdf.*

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planning). Examples are Killen Station Unit 2,[74] and Asheville Unit 1.[75]

• In 2009 the APC supply chain deployed more than six times more GW capacity of FGD and SCR controls than the 5.9 GW of FGD that would be deployed by 2014 under this Rule.

• The APC supply chain has seen a 2-year decline in deployments since its peak in 2009, but in 2011 is nonetheless putting into service about three times more GW capacity of FGD and SCR controls than the 5.9 of FGD that would be deployed under this Rule.

• Because the supply chain has been in decline, but remains quite active, there are now adequate supply chain resources available that can be quickly reengaged to support a rapid deployment of 5.9 GW of FGD.

EPA recognizes that the installation of any amount of scrubbers in this short time frame will require aggressive action by plant owners and that the owners who can meet this schedule will already have done their project planning and will be ready to place orders. An example of such ''early movers'' was seen in the power sector's anticipation of CAIR. EPA data indicate that solely CAIR-driven FGD and SCR deployments of about 6 GW occurred within two and one-half years after CAIR's finalization in mid-2005, showing that at least 20 percent of the total CAIR-only controls effort through a 2010 compliance date was sufficiently planned for installation to start before or immediately upon finalization of the rule. EPA reasonably expects that similar advance planning has already been done for units that would retrofit under this rule.

In the event that a particular control installation requires additional time into 2014 to come online, EPA believes compliance would not be jeopardized given the ability of sources to purchase allowances during that time. This approach could be supported by some sources with FGD that have the ability to increase their SO_2 removal above historic rates, perhaps through relatively low cost upgrades to improve scrubber effectiveness, or by operating scrubbers at higher chemistry ratios. The ability of sources to temporarily or permanently substitute dry DSI for FGD serves as another backstop for any feasibility issues regarding FGD. Note that the updated modeling for this rule projects the addition by 2014 of about 3 GW of DSI for SO_2 control using trona or other sorbent. DSI is a relatively low capital cost technology that readily can be installed in the time frame available for compliance.[76] [77]

It should also be noted that most APC retrofits will involve a source outage for final ''tie-in'' of retrofitted systems to existing systems, during which time emissions from the affected units are zero. For some sources, the duration of this tie-in outage may effectively extend the deadline by which all of the projected emission reductions need to occur.

Although EPA believes that installation of 5.9 GW of FGD at facilities by January 1, 2014 is feasible, EPA also conducted an IPM sensitivity analysis to examine a scenario in which FGD retrofitting by 2014 is not allowed. Results of EPA's ''no FGD build in 2014'' analysis indicate that if the power industry were subjected to the requirements of this rule without an FGD retrofit option for compliance until after 2014, covered units would still be able to meet the Transport Rule requirements in every state while respecting each state's assurance level. (*See* the docket to this rulemaking for the IPM run titled ''TR_No_FGD_in2014_Scenario_Final.'')

In this scenario without the availability of new FGD by 2014, sources in covered states complied with the Transport Rule budgets by using moderate additional amounts of DSI retrofits, switching to larger shares of sub-bituminous coal, and dispatching larger amounts of natural gas-fired generation in lieu of the FGD retrofits that are projected as being most economic under modeling of the Transport Rule remedy. Because new FGD capacity is included in EPA's projection of the least-cost set of SO_2 emission reductions required in Group 1 states, the ''no FGD'' sensitivity scenario did project higher system costs, although these costs were still substantially lower than the remedy EPA modeled in the Transport Rule proposal.

The ''no FGD'' analysis indicates that while the ability of Group 1 states to meet their 2014 SO_2 budgets is facilitated by FGD retrofits, they are by no means required, nor is Transport Rule compliance jeopardized by their absence. Even under a scenario in which sources fail to complete FGD retrofits by 2014, sources in the affected states would have other compliance options available at reasonable cost to meet the state's budget requirements. This analysis shows that Group 1 states would be able to comply with their 2014 SO_2 budgets by relying on other emission reduction opportunities that do not require FGD retrofits. EPA analysis confirms that those alternatives are feasible both in terms of cost and timing.

Finally, EPA recognizes that, when finalized later this year as currently scheduled, the Mercury and Air Toxics Standards (MATS) will require significant retrofit activity at covered sources in the power sector with a 2015 compliance date for that rule. EPA's projections of retrofit activity under the final Transport Rule are highly compatible with its projections of retrofit activity under the proposed MATS (which included the proposed Transport Rule in its baseline). EPA therefore anticipates that the Transport Rule's projected retrofit activity will not only be the least-cost compliance pathway to meeting state budgets in 2014 but will also accelerate emission reductions subsequently required by the effective date of MATS. The final Transport Rule's projected 2014 retrofit installations will also further incentivize the power sector to ramp up its retrofit installation capabilities to achieve broader deployment of the projected pollution control retrofits under the proposed MATS.

Considering all the reasons given above, EPA has concluded that the 2014 requirements for SO_2 emissions in the states covered by the Transport Rule are reasonable and can be met by the power industry by a variety of means.

c. Coal Switching for SO_2 Compliance in 2012 and 2014

Coal switching is another mechanism which can be used along with operating pollution controls in 2012 for compliance. It will be a complementary activity by many coal-fired units alongside of operating pollution controls and the addition of more scrubbers and DSI in 2014.

In the proposal, EPA noted that coal switching could serve as a compliance mechanism for 2012. EPA requested comment on the reasonableness of EPA's assumption that coal switching will have relatively little cost or schedule impact on most units. EPA received substantial comment suggesting that the coal switching and coal blending projected by EPA modeling are not feasible for all units,

[74] Black & Veatch, *http://www.bv.com/News_3_Publications/News_Releases/2005/0503.aspx* (start), *http://www.bv.com/wcm/press_release/07252007_9767.aspx* (completion).

[75] PowerGenWorldwide, Projects of the Year, January 1, 2007, *http://www.powergenworldwide.com/index/display/articledisplay/282547/articles/power-engineering/volume-111/issue-1/features/projects-of-the-year.html.*

[76] ICAC letter to Senator Carper, November 3, 2010, *http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf.*

[77] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011, *http://www.supportcleanair.com/resources/studies/file/4-8-11-URSTechnologyReport.pdf.*

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and that, if feasible, would often incur a cost through the derating of the unit associated with the switch to a lower sulfur coal or coal blend. Additionally, sources indicated that coal switching by 2012 would not always be possible in the six month window between final rule signature and start of compliance. These feasibility concerns stemmed from restrictions included in existing coal supply contracts and from boiler design constraints that may hinder coal switching within a 6 month window.

EPA agrees with these concerns and revised its IPM modeling to limit coal switching capability in 2012 for particular units that may have trouble switching coals or coal blends in a six month time frame. A cost adder was also included in the IPM modeling for coal switching to capture the potential cost burden of deratings that might accompany switching to a very low sulfur subbituminous coal or coal blend.

A particular commenter concern regarding switching to lower sulfur within the eastern bituminous coals related to a possible impact on the performance of a cold-side electrostatic precipitator (ESP). Some ESPs that operate at acceptably high collection efficiency when using a high- or medium-sulfur bituminous coal may experience some loss in collection efficiency when a lower sulfur coal is used. Whether this occurs on a specific unit, and the extent to which it occurs, would depend on the design margins built into the existing ESP, the percentage change in coal sulfur content, and other factors. In any case, industry experience indicates that relatively inexpensive practices to maintain high ESP performance on lower sulfur bituminous coals are available and can be used successfully where necessary. These include a range of upgrades to ESP components and flue gas conditioning.[78] EPA therefore assumes that it will not be necessary for units that switch from higher to lower sulfur bituminous to make a costly replacement of the ESP.

Coal switching as a SO_2 compliance option might also include switching from bituminous to subbituminous coal. EPA's analysis does not assume that a unit designed for bituminous can switch to (very low sulfur) subbituminous coal unless the unit's historical data demonstrate that capability in the past. EPA assumes that units with that demonstrated capability have already made any investments needed to handle a switch back to the use of subbituminous coal at a similar percentage of its heat input as in the past. For IPM analysis in the final rule EPA also introduced a coal switching option that assumes that units can increase a historically low percentage use of subbituminous to a ''maximum'' level, if economic. This option includes an appropriate derate in output, increase in heat rate, and additional capital and operating costs. Details of this and other IPM updates for this rule are provided in the IPM Modeling Documentation in the docket for this rulemaking (''Documentation Supplement for EPA Base Case v.4.10_FTransport—Updates for Final Transport Rule'').

Some commenters also expressed concern with the assumption that coal-switching from lignite to subbituminous is a cost-effective or feasible emission reduction strategy, particularly at Texas EGUs. EPA carefully considered these comments and adjusted its modeling of cost-effective reductions to address this concern. Specifically, EPA made adjustment in the model so that it assumes coal-switching is not a compliance option at the specific units where commenters identified technical barriers to subbituminous coal consumption. The Transport Rule emission budgets are based on this adjusted modeling which does not assume any infeasible coal-switching from lignite to subbituminous. In addition, EPA's analysis of cost-effective reductions in each state presented in section VI.B shows that Texas is capable of cost-effectively meeting its Transport Rule emission budgets; however, EPA also conducted sensitivity analysis that shows Texas can also achieve the required cost-effective emission reductions even while maintaining current levels of lignite consumption at affected EGUs. More details regarding this analysis, including a table comparing key parameters between the main Transport Rule remedy analysis and this Texas lignite sensitivity, can be found in the response to comments document and the IPM model output files included in the docket for this rulemaking.

D. Allocation of Emission Allowances

Under the final rule, EPA distributes a number of SO_2, annual NO_X, and ozone-season NO_X emission allowances to covered units in each state equal to the SO_2, annual NO_X, and ozone-season NO_X budgets for those states. These budgets are addressed in section VI.D of this preamble. This section discusses the methodology EPA uses to allocate allowances to covered units in each state.

As discussed later in section VII.D.2, EPA is setting aside a base 2 percent of each state's budgets for allowance allocations for new units, with 5 percent of that 2 percent, or 0.1 percent of the total state budget being set aside for new units located in Indian country. To this base 2 percent, EPA is setting aside an additional percentage on a state-by-state basis, ranging from 0 to 6 percent (yielding total set asides of 2 percent to 8 percent), for units planned to be built. The remainder of the state budget is allocated to existing units. Tables VI.D.–3 and VI.D.–4 in this preamble show the SO_2, annual NO_X, and ozone-season NO_X budgets for each covered state (without the variability limits). In allocating allowances to existing and new units, EPA distributes four discrete types of emission allowances for four separate programs: SO_2 Group 1 allowances, SO_2 Group 2 allowances, annual NO_X allowances, and ozone-season NO_X allowances.

In the SO_2 Group 1 and SO_2 Group 2 programs, each SO_2 allowance authorizes the emission of one ton of SO_2 in that vintage year or earlier and is usable for compliance only in the program for which the allowance was issued. In the annual NO_X program, each annual NO_X allowance authorizes the emission of one ton of NO_X in that vintage year or earlier in that program. In the ozone-season NO_X program, each ozone-season NO_X allowance authorizes the emission of one ton of NO_X during the regulatory ozone season (May through September for this final rule) in that vintage year or earlier for that program.

In each of the four trading programs, a covered source is required to hold sufficient allowances (issued in the respective trading program) to cover the emissions from all covered units at the source during the control period. EPA assesses compliance with these allowance-holding requirements at the source (*i.e.,* facility) level.

This section explains how, in this final rule, EPA allocates a state's budget to existing units and new units in that state. This section also describes the new unit set-asides and Indian country new unit set-asides in each state, allocations to units that are not operating, and the recordation of allowance allocations in source compliance accounts.

1. Allocations to Existing Units

This subsection describes the methodology EPA will use in the FIPs finalized in this action to allocate to

[78] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011, *http://www.supportcleanair.com/resources/studies/file/4-8-11-URSTechnologyReport.pdf.*

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existing units.[79] The same methodology will be used to allocate allowances to existing units for all four trading programs.

For the reasons explained below, EPA has decided to base allocations made under the FIPs on historic heat input, subject to a maximum allocation limit to any individual unit based on that unit's maximum historic emissions. This methodology gives each existing unit an allocation equal to its share of the state's historic heat input for all the covered units in the program, except where that allocation would exceed its maximum historic emissions; this methodology constrains the heat input-based allocations from exceeding any unit's maximum historic emissions. Further detail on the implementation of this approach is provided in section VII.D.1.c below as well as in the Allowance Allocation Final Rule TSD in the docket for this rulemaking. All existing-unit allocations for 2012 will be made pursuant to the FIPs. However, as described in section X, states may submit SIPs or abbreviated SIPs to use different allocation methodologies for allowances of vintage year 2013 and later.

a. Summary of Allocation Methodologies and Comments

EPA took comment on three distinct allocation methodologies for existing units. The first—an emissions-based option—was presented in the original Transport Rule proposal (75 FR 45309). The second and third—heat input option 1 and heat input option 2—were presented in a Notice of Data Availability (76 FR 1113). EPA received numerous comments on all three options.

i. Emission-Based Allocation Methodology

The emission-based option presented in the original Transport Rule proposal would base allowance allocations to existing units on each covered unit's calculated emission ''share'' of that state's budget for a given pollutant under the Transport Rule. The proposed rule stated that ''for 2012, each existing unit in a given state receives allowances commensurate with the unit's emissions reflected in whichever total emissions amount is lower for the state, 2009 emissions or 2012 base case emissions projections. In either case, the allocation is adjusted downward, if the unit has additional pollution controls projected to be online by 2012. * * * For states with lower SO_2 budgets in 2014 (SO_2 Group 1 states), each unit's allocation for 2014 and later is determined in proportion to its share of the 2014 state budget, as projected by IPM'' (75 FR 45309).

Many commenters objected to this projected emission allocation methodology. Commenters offered two principle objections. First, they argued EPA should not use unit-level model projections to allocate allowances. Second, they argued the use of any emission-based allowance methodology is improper. Many of these commenters argued that instead of an emission-based allocation methodology, EPA should use a heat-input-based allocation methodology.

Commenters' objections to the use of unit level model projections focused primarily on the accuracy of such projections. While many commenters supported the use of modeling projections in determining state emission budgets, they argued that the unit-level model projections were not sufficiently accurate to use as a basis for allocating allowances to individual units. Among other things, they argued that the modeling used for the proposal did not recognize certain non-economic factors that may cause individual units to operate differently than the model projects. Commenters also argued that EPA's modeling does not capture all up-to-date contracts and other economic arrangements made at the unit-level which may affect operational decision-making. Some of these commenters continued to support the use of an emission-based allocation approach, but urged EPA to use more up-to-date and specific unit-level data in its modeling projections. Others opposed the use of any emission-based allocation approach.

EPA acknowledges that the model may not, at this time, capture all relevant operational decision factors for each individual unit. EPA also recognizes that there are unit-level details of operational decision-making and economic arrangements (such as certain contracts for electricity sales) that are private and thus unavailable to EPA on an ongoing basis for modeling purposes. EPA believes these potential omissions would not have a significant impact on EPA's determination of significant contribution at the state level; however, EPA recognizes they could conceivably have a significant impact on projections at the individual unit level. EPA thus agrees with commenters that the unit-level emission projections from its modeling may not reflect all possible operational decisions at a given unit and are therefore not an appropriate proxy measure to use as a basis for allocating allowances to individual units.

Many commenters also argued that, even if the emission projections could be adjusted to capture all known and up-to-date unit-level operational factors, EPA should not use any emission-based allocation approach. They argued that an emission-based approach should not be used because it is not fuel-neutral. That is to say, the type of fuel consumed significantly affects the emissions from, and therefore the allocation to, a given unit under an emission-based approach. Commenters argued that an approach that is not fuel-neutral effectively awards higher-emitting units. Commenters also argued that a projected emission-based approach should not be used because it is not control-neutral. In other words, whether or not a unit has installed controls would significantly affect the allocation for a given unit under an emission-based approach. Under an emission-based approach, controlled units receive significantly fewer allowances than uncontrolled units. Such an approach, commenters pointed out, effectively penalizes sources who have taken action to reduce emissions.

EPA acknowledges that an emission-based approach would not be fuel-neutral or control-neutral. EPA notes that the DC Circuit rejected the fuel adjustment factors that were used in CAIR to adjust state budgets based on the type of fuel burned at each covered unit. *North Carolina,* 531 F.3d 918–21 (rejecting use of fuel adjustments in setting state NO_X budgets). While the proposal's allocation methodology did not explicitly adopt ''fuel adjustment factors'' for allocation purposes, EPA recognizes that an emission-based allocation methodology effectively advantages or disadvantages units based on the type of fuel they combust.

In addition, several commenters argued that the proposal's emission-based methodology would inappropriately reward the highest emitters under the program with more allowances than their lower-emitting counterparts would receive. EPA acknowledges that such a methodology would allocate more allowances to units whose emissions make up a larger share of the proposed Transport Rule programs' state budgets. EPA notes that because any allocation patterns under the Transport Rule FIPs would be established in advance of covered sources' compliance decisions (*i.e.,* decisions regarding how much to emit under the programs), covered sources

[79] In this rule, existing units are defined as covered units that commenced commercial operation prior to January 1, 2010. As explained in greater detail in Section VII.B. of this preamble, EPA decided to use this definition to ensure that EPA would have at least 1 full year of quality-assured data on which to base a unit's allocation.

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cannot be ''rewarded'' by adjusting their future emissions. However, EPA notes commenters' observations that the proposal's methodology would reduce allocations to units that previously installed pollution control technology or invested in cleaner forms of generation in anticipation of CAIR. EPA concluded in review of these comments that the proposed Transport Rule's allocation methodology unintentionally yielded this distributional outcome. EPA therefore considered alternative allocation methodologies described below.

A substantial portion of the commenters who objected to the proposal's emission-based allocation option urged EPA to consider historic heat input based approaches. EPA agreed it should accept comment on the use of historic heat input-based approaches and published a NODA to provide an opportunity for comment on two specific heat input options and the allocations that would result from application of those options to the proposed Transport Rule state budgets.

ii. Heat Input Allocation Option 1

The first heat input option presented by EPA in the NODA (''Option 1'') allocates allowances to units based solely on their historic heat input. Under this option, EPA would establish a 5-year historic heat input baseline for each covered unit and allocate allowances to sources at levels proportional to the each unit's share of the total historic heat input at all covered units in that state.

Numerous commenters supported the use of a heat-input based allocation methodology. These commenters stated that basing allocations on historic heat input has the following advantages over the proposal's emission-based allocation methodology:

(A) For certain types of units, historic heat input data may offer a better representation of unit-level operation than model projections of unit-level emissions; furthermore, for all units, historic heat input is typically represented by quality-assured data reported by sources from continuous emission monitoring systems, which strengthens its accuracy.

(B) Historic heat input data are generally fuel-neutral in that they do not generally yield higher allocations for units burning or projected to burn higher emitting fuels.

(C) Historic heat input data are generally emission-control-neutral in that they do not generally yield reduced allocations for units that installed or are projected to install pollution control technology.

Many commenters also argued that a heat input-based allocation methodology should be used because, unlike the proposal's emission-based methodology, a heat-input based methodology would be generally fuel-neutral and control-neutral and would rely on unit-level quality-assured data instead of on modeling projections.

Several commenters expressed support for specific aspects of heat input option number one. From a technical standpoint, commenters noted that heat input option 1 relied on the highest-quality and most transparent data EPA had provided as a basis for allocating allowances under the Transport Rule programs. They argued that the calculation methodology for heat input option 1 is more readily re-created and understood by sources than either the proposal's methodology or EPA's application of the ''reasonable upper-bound capacity utilization factor and a well-controlled emission rate'' in heat input option 2 (described in greater detail below). They also pointed out that it is similar to methodologies used in previous trading programs, such as the NO_X Budget Trading Program (see 40 CFR 96.42(a) & (b) (calculating each existing EGU's allocation by multiplying each unit's historic heat input by 0.15 lb/mmBtu)). In addition, commenters supported the reliance of heat input option 1 on continuous emission monitoring system (CEMS) data that are reported to EPA and certified by the source's designated representative (DR) as accurate and complete. In addition, many commenters supported EPA's use of historic data without further transformation by any calculation factors created by EPA.

From a policy perspective, commenters highlighted the fuel neutrality and emission-control neutrality aspects of heat input option 1. They noted that this option does not, in contrast to the proposal's emission-based methodology, penalize a source, through a reduced allowance allocation, for having chosen a generation technology or emission control technology that was more favorable to public health and the environment. EPA agrees with these observations. The allocation pattern associated with this option does not advantage or disadvantage units based on either the fuel consumed or the presence or absence of a pollution control technology. In this respect, it is a neutral approach that does not ''reward'' high-emitting units or ''penalize'' low-emitting units, including, for example, those units on which pollution control technology was installed in anticipation of CAIR.

EPA agrees with the aforementioned arguments from these commenters regarding the technical and policy merits of this heat input-based allocation methodology. EPA believes that the quality-assured heat input data reported by EGUs under its programs are among the most detailed and sound unit-level data accessible by EPA. EPA believes the calculation of any individual unit's share of this historic heat input data is a straightforward, clear, and simple calculation to perform, such that EPA's calculated allowance allocations under this approach can be relatively easily replicated.

EPA also agrees with commenters that such data has previously supported allowance allocation procedures for highly successful program implementation of the ARP and the NO_X Budget Trading Program (NBP). Notably, Congress chose a heat input-based allocation approach when authorizing the ARP in title IV of the Clean Air Act, suggesting that Congress viewed heat input as a reasonable basis for allocation. Additionally, EPA's selection of a heat input-based approach for the NBP was not legally challenged, implying that stakeholders generally saw a heat input-based approach as reasonable.

EPA also agrees with comments observing that allocations made under this heat input approach do not advantage or disadvantage units based on their choice of fuel combustion or pollution control technology, and that allocations under this approach would thus be ''fuel-neutral'' and ''control-neutral.'' EPA also agrees with commenters that unlike the proposed rule's emission-based methodology, this heat input methodology does not yield lower allocation to units that reduced emissions in advance of the Transport Rule relative to units that did not make such emission reductions.

Other commenters objected to the use of a heat-input based allocation methodology. These commenters argued that the allocation pattern associated with a heat-input allocation methodology would yield ''windfall profits''—in the form of allowance allocations greatly in excess of likely emissions—for certain units, particularly with regard to SO_2 allowance allocations for units combusting natural gas. EPA disagrees with the characterization of the excess allowances as ''windfall profits.'' Allocations based on heat-input alone are fuel-neutral and control-neutral. The characterization of the heat-input allocation methodology as creating ''windfall profits'' for any unit is based on the assumption that all units should

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be allocated allowances based on emissions, not heat input. In arguing the heat-input approach creates a ''windfall'' for some units, commenters are assuming that the allocation of allowances above a unit's projected emissions constitutes a ''windfall''—a conclusion EPA does not accept. EPA believes that under market-based regulatory programs, it is appropriate to base initial allowance allocations on a neutral factor and allow the market to determine the least-cost pattern of emission reductions in each state to achieve the reductions that address the state's significant contribution and interference with maintenance under the final Transport Rule programs. EPA disagrees that future allowance transactions (following a neutral-factor initial allocation) in response to these market forces can be characterized as ''windfall profits.'' As explained above, EPA believes it is appropriate to allocate allowances based on a neutral factor. Commenters appear to ask EPA, instead of allocating based on a neutral factor, to consider the unit-level distributional impacts of each allocation methodology and to select an allocation methodology on the basis of equity. EPA does not believe it would be appropriate for the agency to pick an allocation methodology to achieve any particular distributional outcome as such considerations are not related to the statutory mandate of CAA section 110(a)(2)(D)(i)(I). Instead, EPA believes it is appropriate to allocate allowances to sources covered by its trading programs based on a neutral factor. Furthermore, CAA section 110(a)(2)(D)(i)(I) requires prohibition of certain emissions within a state (*i.e.,* a state's significant contribution and interference with maintenance). It does not direct EPA to use any particular methodology for allocating allowances under a trading program designed to ensure all such emissions are prohibited. As such, EPA believes it is appropriate to allocate allowances based on a neutral factor representing fossil energy content used to produce electricity. Detailed considerations of equity, as the DC Circuit reminded EPA, are not related to the statutory mandate of section 110(a)(2)(D)(i)(I). *North Carolina,* 531 F.3d 921.

Some commenters objected to the use of a heat input-based approach by arguing that higher-emitting units would not receive an initial allocation sufficient to cover their emissions. EPA does not believe it is reasonable to expect initial allocations to cover each unit's emissions under a trading program aimed at producing meaningful emission reductions. In its administration of prior trading programs such as the ARP and the NBP, EPA has made initial allowance allocations using a heat input-based approach, and virtually all covered sources have successfully complied at the end of each compliance period by making cost-effective emission reductions, purchasing additional allowances through robust markets to cover emissions, or undertaking both types of activities. EPA disagrees with commenters' arguments that allowance allocations should be used to compensate units with higher emissions.

iii. Heat Input Allocation Methodology Option 2

The second heat input option presented by EPA for public comment also would use historic heat input but would apply a constraint to unit-level allocations under certain circumstances. Specifically, under this option unit-level allocations would not be allowed to exceed what EPA determines, based on historic emissions and other factors, to be the units' ''reasonably foreseeable maximum emissions.''

To apply this constraint, EPA first would determine whether the allocation to a unit under an unconstrained heat-input methodology would exceed that unit's maximum historic emissions of the relevant pollutant since 2003 ''in order to reflect unit-level emissions before and after the promulgation of the CAIR'' (76 FR 1115). Using this baseline would enhance the neutrality of the maximum historic emissions data because it would capture the highest emissions of the unit during that period regardless of what fuels it combusted or what pollution control devices were installed and used at any particular time during that period. In other words, a unit's allocation would not be reduced due to a recent decision to switch fuels or install pollution controls.

Second, for this option, EPA then would adjust that maximum historic emissions data by applying a ''well-controlled rate maximum,'' designed to place ''a reasonably foreseeable maximum emissions level reflecting a reasonable upper-bound capacity utilization factor and a well-controlled emission rate that all units (regardless of the type of fuel they combust) can meet for the pollutant'' (76 FR 1115). This option would constrain certain units' allocations that, if based solely on historic heat input, would be determined by EPA to be ''in excess of their reasonably foreseeable maximum emissions'' under the Transport Rule programs (76 FR 1115).

As noted above, commenters offered numerous arguments in favor of using a historic heat input approach. These arguments apply equally to heat input option 1 and heat input option 2. EPA also received numerous comments comparing the two heat input options presented.

Many commenters preferred heat input option 1's reliance purely on historic data as compared with heat input option 2's reliance on that data modified by the application of EPA-determined ''reasonable upper bound capacity factors'' and ''well-controlled emission rates.'' Commenters also criticized the complexity of these modification factors in heat input option 2. While EPA believes both options represent viable approaches, the Agency agrees with commenters that the application of these factors increase the complexity of allocation determinations and would adjust unit-specific historic data by applying EPA-created factors generically determined for broad categories of units.

Some commenters suggested that EPA's application of these modification factors could also represent legal vulnerabilities for the Transport Rule. In particular, they were concerned that the capacity factors and well controlled emission rates presented as part of heat input option 2 could be perceived as arbitrary. While EPA does not agree that these modification factors are arbitrary, the Agency does recognize that application of such EPA-created generic factors in determining unit-specific allocations increases the complexity of the allocation approach and raises issues regarding whether such generic factors are appropriately applied to each individual unit.

iv. General Comments on EPA's Authority To Allocate Allowances

Numerous commenters also noted that EPA has generally broad authority in selecting an allocation methodology under CAA sections 110(a)(2)(D)(i)(I) and 302(y).[80] EPA agrees with commenters that the Agency has broad discretion in this area. Neither the CAA nor the D.C. Circuit Court's opinion in *North Carolina* specifies a particular methodology that EPA must use to allocate allowances to individual units.

[80] CAA section 302(y) defines the term ''Federal implementation plan'' as ''a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.''

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CAA section 110(a)(2)(D)(i)(I) requires prohibition of emissions ''within the state'' that significantly contribute to nonattainment or interfere with maintenance and gives states broad discretion to develop a control program in a SIP that achieves this objective. EPA has similarly broad discretion when issuing a FIP to realize this objective. Moreover, while the definition of FIP in CAA section 302(y) clarifies that a FIP may include ''enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances),'' this section does not require EPA to use any particular methodology to allocate allowances under a FIP trading program. In light of this lack of direction in the CAA concerning allowance allocation, EPA has broad discretion to select an allocation methodology that is reasonable and consistent with the goals of CAA section 110(a)(2)(D)(i)(I).

The body of public comment makes it clear that no allocation option could be deemed satisfactory from the perspective of all stakeholders. Public comments from most states and industrial stakeholders with a substantial interest in how EPA allocates allowances under the Transport Rule FIPs expressed support for an historical heat input-based approach as opposed to the proposal's emission-based approach. Most commenters favored this historical heat input data basis as the most sound and offered technical data corrections, which EPA considered and generally used in the final rule. EPA believes it is reasonable to select a heat input-based approach for the final Transport Rule because this approach is consistent with the rule's statutory objectives and has been found, when implemented in prior trading programs, to be a credible, workable allocation approach.

b. Final FIP Allocation Methodology

After consideration of all comments, EPA decided to allocate allowances to individual units based on that units' share of the state's historic heat-input, but to ensure that no unit's allocations exceed that unit's historic emissions. EPA decided to use the allocation methodology originally presented as heat input option 2, modified in response to public comments. EPA decided to use heat input option 2 but without the application of the ''reasonable upper-bound capacity utilization factor and a well-controlled emission rate'' factors. This allocation approach reflects the Agency's response to extensive public comment on the options presented in the proposed Transport Rule and subsequent NODAs and is a logical outgrowth of those actions. EPA is using this approach to allocate allowances under the FIPs for all four trading programs. Further details on the calculation and implementation of this approach are provided below in section VII.D.1.c and can also be found in the Allowance Allocation Final Rule TSD in the docket for this rulemaking.

The principal reasons for this decision are:

- EPA believes that existing-unit allowance allocation under the Transport Rule should not generally advantage or disadvantage units based on the selection of fuels consumed or of pollution controls installed at a given unit in anticipation of either the Clean Air Interstate Rule or the Transport Rule, *i.e.,* fuel or control decisions taken from 2003 onward. An approach that does not advantage or disadvantage units in this way avoids allocating in a way that would effectively penalize units that have already invested in cleaner fuels or other pollution reduction measures that will continue to deliver important emission reductions under this rulemaking. The approach selected in the final rule generally does not penalize such units and is thus generally fuel-neutral and control-neutral in its allocation determinations.
- EPA finds that the selected approach maximizes transparency and clarity of allowance allocations. EPA has already made public the historic heat input and historic emissions data on which this approach is based, and its application to calculate unit-level allocations in each state under that state's emission budgets finalized in this Transport Rule can be relatively easily replicated.
- EPA finds that quality-assured historic CEMS-quality data used to implement this approach represent the most technically superior data available to EPA at the time of this rulemaking for calculating unit-level allocations. The selected approach relies on unmodified historic data reported directly by the vast majority of covered sources, whose designated representatives have already attested to the validity and accuracy of this data. EPA agrees with commenters that allowance allocations should be based on quality-assured data to the maximum extent possible. This approach uses the most accurate data currently available to EPA.
- Heat-input based approaches were used to allocate allowances under both the NO_X Budget Trading Program and the Acid Rain Program. Allocation under these programs was readily and easily administered, and the programs achieved or exceeded their environmental goals. The selected approach's use of heat input as a basis for allocations builds on prior legislative and administrative approaches to allowance allocations for trading programs.
- EPA also finds that the selected approach's addition of a constraint to heat input-based allocations where such allocations would otherwise exceed a unit's maximum historic emissions is a reasonable extension of a heat input-based allocation approach. The Transport Rule trading programs are established to achieve overall emission reductions in each covered state. As a group, covered sources within each state must make the necessary reductions under these programs. In light of each program's goal to reduce each state's overall emissions, it is logical and consistent with that goal that the starting point for each source under these programs—*i.e.,* the initial allocations of shares of the state budget to covered units—be an amount of allowances no greater than each unit's maximum historic emissions. Under the trading programs, any source may emit a ton of SO_2 or NO_X for which it holds a corresponding allowance, which it may acquire either by initial allocation or by subsequent purchase, to the extent consistent with the assurance provisions (discussed elsewhere in this preamble) that ensure achievement of the requisite overall reductions in each state. Consequently, the initial allocations to the units at each source are the starting point for each source's efforts to comply with the allowance-holding and assurance provision requirements, but do not determine the source's strategies for compliance and ultimate level of emissions. EPA believes that a starting point of unit-level heat input-based allocations constrained not to exceed each specific units' maximum historic emissions is reasonable and consistent with the program goals of reducing overall emissions in each state: Each existing unit is allocated an amount that either reflects reduced unit emissions or does not exceed historic emissions, and, from that starting point, the units, as a group, reduce overall emissions to the level required for each state. Conversely, EPA believes that a starting point allocating some units more than they have ever emitted would be illogical in programs aimed at reducing overall emissions.

EPA believes that this selected allocation methodology for the final Transport Rule FIPs is within its authority under the Clean Air Act. Section 110(a)(2)(D)(i)(I) of the CAA

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requires that emissions ''within a state'' that significantly contribute to nonattainment or interfere with maintenance in another state be prohibited. In the final Transport Rule, EPA analyzed each individual state's significant contribution and interference with maintenance and calculated budgets that represent each state's emissions after the elimination of prohibited emissions in an average year. The methodology used to allocate allowances in a state budget to individual units in the state has no impact on that state's budget or on the requirement that the state's emissions not exceed that budget plus variability. Regardless of the allocation methodology used, the state's responsibility for eliminating its significant contribution and interference with maintenance remains unchanged. This is reflected by the fact that allocations under each state's budget, regardless of how they are made, cannot change that state's budget. In sum, the allocation methodology has no impact on the final rule's ability to satisfy the statutory mandate of CAA section 110(a)(2)(D)(i)(I) to eliminate significant contribution to nonattainment and interference with maintenance.

Consistent with its broad authority in CAA sections 110(a)(2)(D)(i)(II) and 302(y), EPA believes that data quality, fuel-neutrality, control-neutrality, transparency, clarity, consistency with program goals, and successful experience in previous trading programs are reasonable factors on which to base the selection of an allowance allocation methodology for existing units for the final Transport Rule. EPA believes that the transparency and clarity of this allocation approach builds credibility with the public that the government is distributing a public resource—*i.e.,* allowances—precisely as stated in this rulemaking, with clear execution that can be relatively easily verified.

EPA also believes that the final Transport Rule's heat input-based approach for existing units is consistent with the goals of the Clean Air Act because it allocates allowances to existing units on the basis of a neutral factor that does not advantage or disadvantage a unit based on what fuel the unit burns or whether or not a unit has installed controls in anticipation of these regulations. In contrast, allocations under the proposal's emission-based methodology would give a greater share of allowances to units with higher emission rates, which are generally responsible for a greater share of a state's total emissions. Because these higher-emitting rate units are generally responsible for a greater share of emissions, it follows that they are also responsible for a greater share of a state's significant contribution to nonattainment and interference with maintenance. The proposal's emission-based allocation methodology would disadvantage one of two otherwise identical existing units if it invested in emission reductions in anticipation of the Clean Air Interstate Rule or this final Transport Rule.

The heat-input allocation methodology selected for the final Transport Rule does not have this flaw. In contrast to the proposal's emission-based allocation approach, the heat input allocation methodology selected by EPA yields a smaller proportion of allowances relative to emissions to higher-emission-rate units and a higher proportion of allowances relative to emissions to lower-emission-rate units. For example, assume that in a state with two units and in a baseline year, Unit A combusts 100 mmBtu of heat input and emits 1,000 tons while Unit B combusts 100 mmBtu of heat input and emits only 500 tons. Assume also that this state's future Transport Rule emissions budget for this pollutant is only 500 tons. Because Units A and B each make up an even share of historic heat input for the state, the final rule's heat input-based approach would allocate the same share of allowances (250 tons) to each unit. In this example, Unit A's initial allocation of 250 is a smaller proportion of its historic emissions (25 percent of its baseline 1,000-ton emissions), while Unit B's initial allocation of 250 is a larger proportion of its historic emissions (50 percent of its baseline 500-ton emissions). Therefore, Unit B's ability to emit fewer tons per mmBtu of heat content used for generating electricity (as compared with Unit A) results in Unit B receiving a larger proportion of its historic emissions as an initial allocation share than Unit A receives.

This relative distributional pattern yielded is consistent with the goals of CAA section 110(a)(2)(D)(i)(I) because under this distribution, higher-emitting units, which are responsible for a greater share of the state's significant contribution to nonattainment and interference with maintenance, would require relatively more allowances in order to cover their pre-existing emissions than would lower-emitting units. EPA believes this initial allocation pattern is an appropriate reflection of the goals of CAA section 110(a)(2)(D)(i)(I).

The heat input-based allowance methodology selected by EPA is fuel-neutral, control-neutral, transparent, based on reliable data, and similar to the allocation methodologies used in the NO_X SIP Call and Acid Rain Program. For all these reasons, EPA determined that it is appropriate to use a heat input-based allocation methodology in this rule.

In addition, this allocation methodology is similar to an output-based allocation approach, which would base allocations on the quantity of electricity generated (rather than energy content combusted) and would also be fuel-neutral, control-neutral, and able to reward generation units that operate the most efficiently. Many state and industry commenters advocated using an output-based approach due to its reported strong value in promoting efficiency. However, at this time EPA does not have access to unit-level output data that is as quality-assured or comprehensive as its data sets on heat input across the units considered. Therefore, EPA is using a heat input-based approach under the Transport Rule in part due to its ability to serve as a reasonable proxy for an output-based standard using the most quality-assured data that EPA has to date.

In the NODA, EPA noted that final state budgets and allocations may differ from the proposed budgets and allocations because EPA was still in the process of updating its emission inventories and modeling in response to public comments, including comments on IPM. Thus, unit-level allocations in the NODA provided an indication of the proportional share of a state's budget that would be allocated to individual existing units if the alternative methodologies were used. The allocations made final today are based on budgets that reflect the updated modeling and comments received during the comment period.

c. Calculation of Existing Unit Allocations Under the Final Transport Rule FIPs

Allocations under this final methodology for each existing unit are determined by applying the following steps.

1. For each unit in the list of potential existing Transport Rule units, annual heat input values for the baseline period of 2006 through 2010 are identified using data reported to EPA or, where EPA data is unavailable, using data reported to the Energy Information Administration (EIA). For a baseline year for which a unit has no data on heat input (*e.g.*, for a baseline year before the year when a unit started operating), the unit is assigned a zero value. (Step 2 explains how such zero values are treated in the calculations.) The allocation method uses a 5-year

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baseline to approximate a unit's normal operating conditions over time.

2. For each unit, the three highest, non-zero annual heat input values within the 5-year baseline are selected and averaged. Selecting the three highest, non-zero annual heat input values within the five-year baseline reduces the likelihood that any particular single year's operations (which might be negatively affected by outages or other unusual events) would determine a unit's allocation. If a unit does not have three non-zero heat input values during the 5-year baseline period, EPA averages only those years for which a unit does have non-zero heat input values. For example, if a unit has only reported data for 2008 and 2009 among the baseline years and the reported heat input values are 2 and 4 mmBtus, respectively, then the unit's average heat input used to determine its pro-rata share of the state budget is (2+4)/2 = 3.

3. Each unit is assigned a baseline heat input value calculated as described in step 2, above, referred to as the ''3-year average heat input.''

4. The 3-year average heat inputs of all covered existing units in a state are summed to obtain that state's total ''3-year average heat input.''

5. Each unit's 3-year average heat input is divided by the state's total 3-year average heat input to determine that unit's share of the state's total 3-year average heat input.

6. Each unit's share of the state's total 3-year average heat input is multiplied by the existing-unit portion of the state budget (*i.e.*, the state budget minus the state's new unit set-aside and, if applicable, minus the Indian country new unit set-aside) to determine that unit's initial allocation.

7. An 8-year (2003–2010) historic emissions baseline is established for SO_2, NO_X, and ozone-season NO_X based on data reported to EPA or, where EPA data is unavailable, based on EIA data. This approach uses this 8-year historic emissions baseline in order to capture the unit-level emissions before and after the promulgation of CAIR.

8. For each unit, the maximum annual historic SO_2 and NO_X emissions are identified within the 8-year baseline. Similarly, the maximum ozone season NO_X emissions from the 8-year baseline for each unit are identified. These values are referred to as the ''maximum historic baseline emissions'' for each unit.

9. If a unit has an initial historic heat-input based allocation (as determined in step 6) that exceeds its maximum historic baseline emissions (as determined in step 8), then its allocation equals the maximum historic baseline emissions for that unit.

10. The difference (if positive) under step 9 between a unit's historic heat-input-based allocation and its ''maximum historic baseline emissions'' is reapportioned on the same basis as described in steps 1 through 6 to units whose historic heat-input-based allocation does not exceed its maximum historic baseline emissions. Steps 7, 8, and 9 are repeated with each revised allocation distribution until the entire existing-unit portion of the state budget is allocated. The resulting allocation value is rounded to the nearest whole ton using conventional rounding.

Table VI.D–1 below provides an illustrative application of the steps 1–10 in a hypothetical state.

TABLE VI.D–1—DEMONSTRATION OF ALLOCATIONS USING FINAL ALLOCATION METHODOLOGY IN A THREE-UNIT STATE WITH AN 80-TON STATE BUDGET

	Steps 1–6	Steps 7, 8, 9	Steps 1–9 reiterated	Step 10
	Initial historic heat input-based allocation	Maximum historic baseline emissions	Revised historic heat input-based allocation	Final allocation
Unit A	20	16	N/A	16
Unit B	30	50	32	32
Unit C	30	50	32	32

2. Allocations to New Units

EPA is finalizing—similar to the proposal (75 FR 45310)—an approach to allocate emission allowances to new units from new unit set-asides in each state. A ''new unit'' may be any of the following: (1) A covered unit commencing commercial operation on or after January 1, 2010; (2) any unit that becomes a covered unit by meeting applicability criteria subsequent to January 1, 2010; (3) any unit that relocates into a different state covered by the Transport Rule; [81] and (4) any existing covered unit that stopped operating for 2 consecutive years but resumes commercial operation at some point thereafter.

The proposed Transport Rule would have required that owners and operators initially request allowances from the new unit set-aside when the unit first became eligible for an allocation. EPA now believes that it can identify which units become eligible and when they become eligible, based on information provided in other submissions (*e.g.*, certificates of representation, monitoring system certifications, and quarterly emissions reports) that the final rule already requires such units to make to EPA. EPA concludes that requiring owners and operators to submit requests of new unit set-aside allocations would impose an unnecessary burden on the owners and operators, as well as on EPA, and therefore EPA has removed this requirement in the final rule.

The following sections describe the methodology in the final Transport Rule for allocating to new units, how EPA determined the size of new unit set-asides in the final rule, and how EPA has provided for allocations to new units that locate in Indian Country.

a. New Unit Allocation Methodology

The proposal's new unit allocation methodology did not provide any allocation for a new unit's first control period of commercial operation. Some commenters expressed concern about the lack of new unit allocations the first year of commercial operation. In order to address this concern, EPA is modifying the new unit allocation methodology in this final rule to include allocations to new units for the first control period in which the units are in commercial operation, as well as for control periods in subsequent years.

[81] Existing- or new-unit allocations drawn from the budget of the relocated unit's original state are replaced by new unit set-aside allocations from the budget of the unit's relocation state in order to generally ensure that allocations are drawn from the correct state budget.

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The final rule's allocation to new units is performed in two ''rounds.'' The first round is the same as the new unit allocation procedures in the proposal (except for elimination of the requirements that owners and operators request the allocations) and occurs during the control period for which the allocations are made. These first round allocations are based on new unit emissions during the prior control period and are recorded in allowance accounts in the Allowance Management System for the units by August 1 of each control period. For example, for the 2012 vintage year, ''first-round'' allocations would be made to new units by August 1, 2012 based on their emissions in the 2011 control period (as monitored and reported in accordance with Part 75 of the Acid Rain Program regulations). If the new unit set-aside is insufficient to accommodate first round allocations reflecting all new units' prior control period emissions, the first round allocations are made pro rata to new units based on their share of total new unit emissions in the prior control period.

The second round of allocations accommodates new units that come online during the control period for which the allocations are made and did not therefore receive any allocation in the first round. The second round also accommodates new units that come online partway into the prior control period and therefore received an allocation in the first round that did not extend to cover operations in a full control period. This second round of new unit allocation is therefore applicable only to new units coming online either during the control period of the allocation or during the control period immediately prior. New units coming online earlier than the previous control period only receive first-round allocations from the new unit set-asides, as first-round allocations to those units are based on operational data spanning an entire control period.

Second-round allocations are based on new unit emissions during the same control period as the vintage year of the allowances allocated. For example, for the 2012 vintage year, ''second-round'' allocations are based on the difference between the new unit's emissions in the 2012 control period and the new unit allocation (if any) that the unit received in the first round of allocations. For a unit coming online in 2012, this amount equals its total emissions during the 2012 control period. For a unit coming online in 2011, this amount equals its incremental emissions in 2012 beyond its emissions in 2011, as such a unit would have already received a first-round allocation from the new unit set-aside based on its emissions in 2011. Second-round allocations are recorded in allowance accounts by November 15 for the NO_X ozone season trading program (ahead of the December 1 compliance deadline) and by February 15 of the following calendar year for NO_X and SO_2 annual trading programs (ahead of the March 1 compliance deadline).

This methodology only allocates in the second round whatever allowances remain in the new unit set-asides after the first-round allocations have been recorded. If the new unit set-aside available for second round allocations is insufficient to accommodate allocations based on the difference between control period emissions and any first round allocations for the units involved, then the second round allocations are made pro rate to the new units based on their share of the total of such differences.

b. Determination of New Unit Set-Asides

The proposed Transport Rule identified new units using a threshold online date of January 1, 2012, whereas the final Transport Rule uses a threshold online date of January 1, 2010. As explained above, EPA adjusted this cutoff date because the final Transport Rule's allocation methodology for existing units requires that EPA possess at least 1 full year of historic data in order to calculate allocations. As a consequence, EPA recognizes that the proposal's methodology to determine the size of the new unit set-asides based only on new EGUs forecast by the model would fail to account for known EGUs that have come online, or are planned to come online, after January 1, 2010. Therefore, EPA has modified its approach to determining the size of the new unit set-asides in the final rule to account for both ''potential'' units (*i.e.*, those that are not yet planned or under construction but are projected by modeling to be built) and ''planned'' units (*i.e.*, those that are known units with planned online dates after January 1, 2010). EPA uses the distinction between ''potential'' and ''planned'' new units to determine the ultimate size of each state's new unit set-aside (as a percentage of that state's budgets for each pollutant covered); however, the new unit allocation methodology described above applies the same to ''potential'' and ''planned'' new units.

The first step of EPA's analysis to determine the new unit set-asides accounts for likely future emissions from potential units, and its methodology is taken directly from the Transport Rule proposal but reflects updated modeling (*see* ''Allowance Allocation to Existing and New Units Under the Transport Rule Federal Implementation Plans'' TSD for detailed findings). This analysis informed EPA's decision to establish a minimum new unit set-aside size of 2 percent of each state's budget for each pollutant that is configured to accommodate future emissions from potential units.

For the final rule, EPA augmented its new unit set-aside determination to account for ''planned'' units through an additional step. Because the location of these ''planned'' units is known and identified in EPA modeling, this second step is a state-specific modification of the size of the new unit set-asides. That is, EPA only increased new unit set-asides above the 2 percent minimum established in the first step for states that had additional known units coming online between January 1, 2010, and January 1, 2012.

The increases made to the new unit set-asides for these planned units reflect the projected emissions from these units. Therefore, if the expected emissions of a given pollutant from all ''planned'' new units in a given state were equal to 3 percent of that state's budget for that pollutant, then EPA added that amount to the base 2 percent new unit set-aside (creating a hypothetical new unit set-aside of 5 percent for that pollutant in that state). *See* ''Allowance Allocation to Existing and New Units Under the Transport Rule Federal Implementation Plans'' TSD for detailed results showing how EPA determined the size of each new unit set-aside reflecting the application of both of the steps described above. This approach to determining the size of state new unit set-asides is a logical outgrowth of the proposal, the NODA on allowance allocations, and updated modeling results. In fact, EPA received comments that using a January 1, 2010 cutoff date for distinguishing between existing and new units would result in the new unit set-aside, as proposed, being insufficient to meet the needs of units already under construction. EPA believes that the approach adopted in the final rule results in new unit set-asides that reasonably accommodate the foreseeable emissions from both planned and potential new units in each state.

The new unit allocation percentages for each state are shown in Table VII.D.2–1.

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TABLE VII.D.2–1—PERCENTAGE OF STATE EMISSION BUDGETS FOR ALLOWANCES IN STATE NEW UNIT SET-ASIDES

	Annual SO_2	Annual NO_X	Ozone-season NO_X
Alabama	2%	2%	2%
Arkansas			2%
Florida			2%
Georgia	2%	2%	2%
Illinois	5%	8%	8%
Indiana	3%	3%	3%
Iowa	2%	2%	
Kansas	2%	2%	
Kentucky	6%	4%	4%
Louisiana			3%
Maryland	2%	2%	2%
Michigan	2%	2%	
Minnesota	2%	2%	
Mississippi			2%
Missouri	2%	3%	
Nebraska	4%	7%	
New Jersey	2%	2%	2%
New York	2%	3%	3%
North Carolina	8%	6%	6%
Ohio	2%	2%	2%
Pennsylvania	2%	2%	2%
South Carolina	2%	2%	2%
Tennessee	2%	2%	2%
Texas	5%	3%	3%
Virginia	4%	5%	5%
West Virginia	7%	5%	5%
Wisconsin	5%	6%	

c. Procedures for Allocating New Unit Set-Asides

For the first round of new unit set-aside allocations, the Administrator will promulgate a notice of data availability informing the public of the specific new unit allocations and provide an opportunity for submission of objections on the grounds that the allocations are not consistent with the requirements of the relevant final rule provisions. A second notice of data availability will subsequently be promulgated in order to make any necessary corrections in the specific new unit allocations. As discussed elsewhere in this preamble, the final rule establishes a different schedule for promulgation of these notices of data availability than the proposed rule. In particular, a single set of deadlines (*i.e.*, for the first notice in the first round of allocations, June 1 of the year for which the new unit allocations are described in the notice and, for the second notice of the first round, August 1 of that year) for promulgation of the notices is established for all of the Transport Rule trading programs. EPA believes that these deadlines will provide sufficient time for EPA to obtain final emissions data for the prior year for the units involved and to calculate the allocations and promulgate the notices. Further, the approach of using the same deadline for all of the Transport Rule trading programs will simplify EPA's implementation and reduce the complexity of the process for source owners and operators.

For the second round of new unit set-aside allocations, the Administrator will also promulgate two notices of data availability. However, the deadlines for the notices differ for the NO_X ozone season trading program and for the SO_2 and NO_X annual trading programs because control period emissions data (used in making second round allocations) become available sooner, and the compliance deadline for holding allowances covering emissions is sooner, in the NO_X ozone season trading program. The control period in the NO_X ozone season program ends on September 30, and fourth quarter emissions reports must be submitted to EPA by October 30, while the control periods in the SO_2 and NO_X annual programs end on December 31 and fourth quarter emission reports are due by January 30. Further, in order for the second round allocations to be available to be used for compliance with the allowance-holding requirement, the second round needs to be completed before the compliance dates, which are December 1 in the NO_X ozone season program and March 1 in the SO_2 and NO_X annual programs. Consequently, for the NO_X ozone season program the Administrator will promulgate by September 15 a notice of data availability identifying the units eligible for second round allocations and by November 15 a second NODA of the list of eligible units and their second round allocations, which will also be recorded in the allowance accounts by that date. The comparable deadlines for the SO_2 and NO_X annual programs are December 15 and February 15. EPA believes that these deadlines will provide sufficient time for EPA to identify the units and obtain their needed emissions data and to calculate the allocations and promulgate the notices.

d. Addition of Allowances to New Unit Set-Asides

As discussed elsewhere in this preamble, EPA proposed that, if a unit with an existing-unit allocation does not operate for 3 consecutive years, the allowances that would otherwise have been allocated to that unit, starting in the seventh year after the first year of non-operation, would be allocated to the new unit set-aside for the state in which the retired unit is located. EPA is retaining this provision in the final rule but is changing the time of non-operation to 2 years and the time of allowance allocation to a non-operating unit to 4 years. Starting in the fifth year of non-operation, allowances will be allocated to the new unit set-aside for the state in which the non-operating unit is located.

EPA received comments that the new unit set-asides were not sufficient to

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encourage the operation of new units. One commenter suggested that allowance allocations should cease after 3 years of non-operation because the financial incentive gained from receiving allowances beyond the 3-year period is insignificant relative to operating and fuel costs. Another commenter said that providing allowances to non-operating units is unnecessary and distorts the market.

In addition to increasing the size of the new unit set-aside in this final rule, as described above, EPA is terminating existing unit allocations starting in the fifth year after the unit does not operate for 2 consecutive years and reallocating to the new unit set-aside the allowances that the unit otherwise would have received for the fifth and subsequent years in order to make them available for new units in the state. This approach allows the new unit set-asides to grow over time.

e. Allocations to New Units Locating in Indian Country

EPA received several comments on the proposed rule that it did not explicitly address the distribution of allowances to potential new units built in Indian country. EPA recognized this concern and requested comment on this topic in the January 7, 2011 NODA.

In the final rule, EPA is providing a mechanism to make allowances available in the future for new units built in Indian country. The final rule establishes an Indian country new unit set-aside for each pollutant in each state whose borders encompass Indian country (*i.e.,* Florida, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Nebraska, New York, North Carolina, South Carolina, Texas, and Wisconsin). EPA will retain administration of these Indian country new unit set-asides as part of the Transport Rule trading programs whether or not a Transport Rule state elects to modify or replace the Transport Rule FIPs through approved SIP revisions. EPA does not create Indian country new unit set-asides for states lacking Indian country within their borders.

EPA determined the size of each Indian country new unit set-aside by calculating the ratio of square mileage of Indian country to the square mileage of the state within whose borders Indian country is located. This calculation yielded a maximum percentage of 5 percent when assessing all of the states encompassing Indian country subject to the final Transport Rule; this is referred to as the ''5 percent Indian country factor'' below. To determine the maximum percentage, EPA used the American Indian Reservations/Federally Recognized Tribal Entities dataset, which contains data for the 562 federally recognized tribal entities in the contiguous U.S. and Alaska. EPA accessed the data to analyze the Transport Rule region and compare the square miles of Indian country with the square miles of the Transport Rule state that includes the Indian country. EPA then took the highest percentage as the number to be applied across all states with Indian country to determine the size of the Indian country new unit set-aside pertinent to that state's budgets under the Transport Rule. EPA chose to use the maximum percentage (5 percent) from the Indian country analysis to determine the Indian country set-aside for each state on the basis that this approach would reserve a reasonable number of allowances from each state's budget for potential allocation to new units that may locate in Indian country within that state's borders. Any allowances from the Indian country new unit set-aside that are not allocated in a given control period are redistributed into the state's new unit set-aside. As discussed above, any allowances not allocated from that new unit set-aside are redistributed to existing units based on the existing units' share of the total existing unit allocations.

To calculate the size of each tribal new unit set-aside, EPA applied this 5 percent Indian country factor to the portion of the state's new unit set-aside originally determined by accounting for ''potential'' new units, which as described above was set at 2 percent of each pollutant's budget in each state. Therefore, the Indian country new unit set-aside is 5 percent of 2 percent of a state's budget, or 0.1 percent of that total state budget. EPA did not apply the 5 percent Indian country factor to the state-specific planned unit portion of each state's new unit set-aside because the planned unit portion is determined using projected emissions from specific, known units coming online after January 1, 2010, and none of these known units are located in Indian country.

The Indian country new unit set-asides in the following Transport Rule states with Indian Country are shown in Table VII.D.2–2.

TABLE VII.D.2–2—NEW UNIT SET-ASIDE ALLOWANCES FOR INDIAN COUNTRY

[Tons]

	SO_2 2012–2013	SO_2 2014 and beyond	Annual NO_X 2012–2013	Annual NO_X 2014 and beyond	Ozone-season NO_X 2012–2013	Ozone-season NO_X 2014 and beyond
Florida	....	....	....	....	28	28
Iowa	107	75	38	38	....	....
Kansas	42	42	31	26	....	....
Louisiana	....	....	....	....	13	13
Michigan	229	144	60	58	....	....
Minnesota	42	42	30	30	....	....
Mississippi	....	....	....	....	10	10
Nebraska	65	65	26	26	....	....
New York	27	19	18	18	8	8
North Carolina	137	58	51	42	22	18
South Carolina	89	89	32	32	14	14
Texas	244	244	134	134	63	63
Wisconsin	80	40	32	30	....	....

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Under the FIPs, EPA allocates allowances from Indian country new unit set-asides in essentially the same manner as it allocates allowances from state new unit set-asides. The approach for identifying, and determining the number of allowances allocated to, new units in Indian country is the same as the approach for identifying and determining allocations for non-Indian country new units covered by the state new unit set-aside, and allocations are made in two rounds using the same schedules for promulgation of notices of data availability. However, as discussed above, unallocated allowances in the Indian country set-asides are handled differently from unallocated allowances in the state new unit set-asides in that unallocated Indian country new unit set-aside allowances are first transferred back into the state new unit set-aside and then, if still not allocated to new units, are distributed to existing units in the state. EPA believes that the above-described approach in establishing and handling the Indian country new unit set-asides and state new unit set-asides is a reasonable way of making a sufficient amount of allowances available for new units in the state and Indian country located in the state and ensuring that the entire state budget is available to either new or existing units in the state and Indian country. EPA retains administration of these Indian country new unit set-asides (and, of course, the portions of state budgets that comprise these set-asides) as part of the Transport Rule trading programs even if a state elects to modify or replace the Transport Rule FIPs through approved SIP revisions. EPA continues to manage and distribute the Indian country new unit set-aside allowances in the same manner as under the FIPs. Unallocated allowances in the Indian country new unit set-aside will be returned to the portion of the state budget allocated under the approved SIP's allocation provisions. EPA believes that this approach is reasonable because EPA, rather than the states, has the authority and responsibility of administering the Transport Rule with regard to new units that locate in Indian country.

E. Assurance Provisions

To ensure that the FIPs require the elimination of all emissions that EPA has identified that significantly contribute to nonattainment or interfere with maintenance within each individual state, the Agency is adopting assurance provisions in addition to the requirement that sources hold allowances sufficient to cover their emissions. These assurance provisions limit emissions from each state to an amount equal to that state's trading budget plus the variability limit for that state (*i.e.,* the state assurance level). As discussed in section VI of this preamble, this variability limit takes into account the inherent variability in baseline EGU emissions and recognizes that state emissions may vary somewhat after all significant contribution to nonattainment and interference with maintenance are eliminated. This approach also provides sources with flexibility to manage growth and electric reliability requirements, thereby ensuring the country's electric demand will be met, while meeting the statutory requirement of eliminating significant contribution to nonattainment and interference with maintenance.

Starting in 2012, EPA is establishing, as part of the FIPs, limits on the total emissions that may be emitted from EGUs at sources in each state. For any single year, the state's emissions must not exceed the state budget with the variability limit allowed for any single year for that state (*i.e.,* the state's 1-year variability limit). In other words, in addition to covered sources being required to hold allowances sufficient to cover their emissions, the total sum of EGU emissions in a particular state cannot exceed the state budget with the state's 1-year variability limit in any 1 year (*i.e.,* the state's assurance level). EPA is not finalizing 3-year variability limits that were included in the proposal for the reasons explained previously in section VI.E of this preamble. The state budgets, variability limits, and state assurance levels for each state are shown in Tables VI.F–1, VI.F–2 and VI.F–3 in section VI.F of this preamble. The basis for the variability limits is also described in section VI.E of this preamble. Additional details may be found in the Power Sector Variability Final Rule TSD in the docket to this rule.

To implement this requirement, EPA first evaluates whether any state's total EGU emissions in a control period exceeded the state's assurance level. If any state's EGU emissions in a control period exceed the state assurance level, then EPA applies additional criteria to determine which owners and operators of units in the state will be subject to an allowance surrender requirement. In applying the additional criteria, EPA evaluates which groups of units at the common designated representative (DR) level had emissions exceeding the respective common DR's share of the state assurance level (regardless of whether the source had enough allowances to cover its emissions) during the control period.[82]

The requirement that owners and operators surrender allowances under the assurance provisions will be triggered only if two criteria are met: (1) The group of sources and units with a common DR are located in a state where the total state EGU emissions for a control period exceed the state assurance level; and (2) that group with the common DR had emissions exceeding the respective DR's share of the state assurance level. The share of the assurance penalty borne by the owners and operators will be based on the amount by which the total emissions for the units in the group exceed the common DR's share of the state assurance level as a percentage of the total calculated for all such groups of sources and units in the state. Thus, the owners and operators of each such group of sources and units must surrender an amount of allowances equal to the excess of state EGU emissions over the state assurance level multiplied by the owners' and operators' percentage and multiplied by two (to reflect the penalty of two allowances for each ton of the state's excess EGU emissions). *See* Table VII.E–1 below for an illustrative example.

This approach in the final rule of implementing the assurance provisions on a common designated representative basis contrasts with the approach in the proposed rule of implementing the assurance provisions on an owner basis. In the January 7, 2011 NODA, EPA requested comment on the alternative of basing the assurance provision penalty using common designated representatives, and some commenters supported this alternative. The common designated representative approach is simpler and avoids the need to collect information on percentage ownership (which information is not used in any other provisions of the Transport Rule trading programs).

In addition, the common designated representative approach provides additional flexibility to owners and operators who have only one or a few units in a given state but have the option of selecting a common designated representative with owners and operators of other units in the state. EPA expects companies in various states will readily be able to manage their

[82] A group of one or more sources and units in a state has a common designated representative where the same individual is authorized as the designated representative (not the alternate designated representative) for that group of sources and units as of April 1 immediately following the allowance transfer deadline for the control period involved.

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emissions to stay collectively below their state's assurance levels as they track emissions quarterly throughout the year and manage their generation units and pollution control efforts accordingly. However, if the state appears to be approaching its assurance level, this final rule also gives companies the ability to further ensure that they will not have excess emissions by combining multiple units under a common DR. This flexibility allows utilities to re-balance allowances and emissions to mitigate penalty risk if the state violates its assurance level. In a state that does not appear to risk violating its assurance level in a given period, utilities would not need to consider the assurance aspect of selecting DRs. However, EPA anticipates that in the event utilities desire additional certainty or mitigation of assurance penalty risk, they will take advantage of this common DR provision or pursue similar private arrangements with each other to cover their emissions at the lowest possible cost.

While the DR provision could benefit utilities by allowing them to pool their penalty risk, the utilities would still be subject to the antitrust laws. As with any joint venture between competitors, the efficiency benefits of pooling risk would be weighed against any anticompetitive harm associated with DRs.

This new feature in the final rule, in conjunction with the simplifications to the final rule's variability limits described in section VI.E, will give companies under the air quality-assured trading program greater flexibility in each state to determine the most cost-effective pattern of emission reductions while EPA ensures each state meets its assurance level needed to address the significant contribution in each state.

In the January 7, 2011 NODA, EPA also requested comment on continuing to link allocations to assurance provision allowance surrender requirements. Even though the final rule uses a different allowance allocation methodology than the allocation methodology that was proposed, the final rule continues to treat the groups of units with greater emissions than their allocations plus share of state variability as responsible for the state's excess of emissions over the state assurance level. EPA believes that this approach is reasonable because any state that exceeds its state assurance level likely does so because not all units have made the reductions necessary to eliminate the state's contribution to nonattainment or interference with maintenance. Moreover, the groups of units with emissions exceeding their allocations plus share of variability are the units most likely to have contributed to the state's exceedance of its state assurance level and thus to the state's triggering of the assurance provisions. Consequently, EPA concludes that it is reasonable to penalize owners and operators of those sources and units (grouped by common DR) for the state's exceedance through application of the assurance provision allowance surrender requirement. Some commenters stated that this is a reasonable approach.

While a few commenters suggested alternative approaches to the assurance provisions, EPA believes that the suggested alternatives are not workable and are likely to create implementation problems. These commenters suggested variations of approaches that would have created state-specific and vintage year-specific allowances that would have been traded independently of compliance allowances. These differentiated allowances would have fragmented the allowance markets and made the programs resemble the intrastate trading option that EPA rejected because of market power and other concerns described in the proposal.

The existence of the assurance provisions with significant penalties imposed if a state's emissions exceed the state budget with the variability limit, along with other features of the Transport Rule trading programs discussed below, will ensure that state emissions stay below the level of the budget with the variability limit. In making compliance decisions and determining to what extent to rely on purchased or banked allowances, owners and operators will have to take into account the risk of triggering the assurance provisions in the state involved and of incurring significant assurance provision penalties. The greater the extent to which units sharing a common DR have emissions exceeding the DR units' allocations plus share of the state variability limit, the greater the risk of being subject to the assurance provision penalties.

As discussed previously in section VII.D.2, EPA allocates allowances to a new unit for the control period during which the unit commences commercial operation from the new unit set-aside based on its emissions. In the case where assurance provisions for a state are triggered in the year that a new unit commences operation, the unit's share of the state assurance level is calculated using the unit's allocation from the new unit set-aside plus its proportional share of the variability limit. There is the possibility that a new unit would receive no allocation for the control period during which the unit commences commercial operation. EPA sees no reasonable basis for disadvantaging owners and operators because they started up a new unit and EPA had no emissions data on which to base an allocation from the new unit set-aside or no allowances were available for the unit in the state's new unit set-aside.[83] For these new units, EPA would use a specific surrogate number to calculate the maximum amount of emissions that the unit would likely have had during that year. The surrogate emission number applies only if the state's assurance provisions are triggered and only in the first year of the new unit's commercial operation for a new unit that did not receive an allocation from the set-aside. The methodology for calculating the surrogate emission number is essentially unchanged from the proposal (75 FR 45313). For more details on capacity factors for new units, see ''Capacity Factors Analysis for New Units Final Rule TSD.''

These assurance provisions are above and beyond the fundamental requirement for each source to hold enough allowances to cover its emissions in the control period. Failure to hold enough allowances to cover emissions is a violation of the CAA, subject to an automatic penalty and discretionary civil penalties, as described in section VII.F of this preamble.

Several features of the air quality-assured trading programs work in conjunction with the assurance provisions to ensure state emissions do not exceed state assurance levels. The air quality-assured trading programs have: State-specific budgets that do not include the variability limits and that are the basis for allocating allowances in each state so that total allocations in a state cannot exceed the state budget; a requirement that owners and operators of each source hold enough allowances to cover source emissions for each control period; assurance provisions that require owners and operators to hold a significant amount of additional allowances in a state if the assurance provisions are triggered; and additional penalties for failing to hold sufficient allowances under the assurance provisions. The underlying mechanism of cap and trade—with a cap on allowances issued and a requirement to

[83] Some other units (*e.g.,* those units with no data for the 2006–2010 base period) may have a zero allocation for a control period. However, those are highly likely to be units that will continue to operate rarely or not at all and so will incur little or none of the assurance provision penalties.

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hold allowances covering emissions—has succeeded, even without assurance provisions, in broadly reducing emissions below allowance allocation levels. The accumulated data, history, and experience from cap and trade programs underscore that emission reduction requirements and environmental and public health goals of the programs have been met and, in many instances, exceeded. Additionally, EPA has now added assurance provisions to ensure that emissions within a state do not exceed the state budget with the variability limitation that eliminates the state's significant contribution to nonattainment and interference with maintenance in downwind states.

Emissions from a common DR's group of units in excess of the DR's share of the state budget with the variability limit are not a violation of the rule or the CAA, but do lead to strict allowance surrender requirements. Specifically, the owners and operators with a common DR will be required to surrender two allowances for each ton of their proportional share of the exceedance of the state budget with the variability limit. Failing to hold sufficient allowances to meet the allowance surrender requirement will be a violation of the regulations and the CAA and subject to discretionary civil penalties under CAA section 113. Allowances surrendered to meet an assurance provision penalty may be from the year immediately following the control period in which the state assurance level was exceeded (*i.e.,* the year during which the penalty is assessed) or any prior year. Any future vintage allowances beyond the year in which the penalty is assessed may not be used to meet an assurance provision penalty.

This penalty level is a change from the proposal, in which one allowance was to be surrendered for each ton of emissions over the state assurance level. EPA ran an IPM modeling scenario in order to assess the level of penalty that would be sufficient to deter sources from exceeding state assurance levels. According to the model, no state would exceed its assurance level and incur the two-for-one allowance penalty in either 2012 or 2014, although some states emit up to the assurance level. The two-for-one allowance surrender requirement is significant, and EPA believes that this penalty—along with the other elements of the Transport Rule discussed above—will be sufficient to ensure that the state emissions will not exceed the budgets plus the variability limits. *See* the Assurance Penalty Level Analysis Final Rule TSD for further details of the analysis.

Below are examples of how the penalty will be assessed for four common designated representatives in the same state if the assurance provisions are triggered. In the first case, DR1's combined units were allowed to emit up to 71 tons of SO_2 (60 * 118 percent), but actually emitted 75 tons during the control period, or 4 more than their share of the state assurance level. Since the state, as a whole exceeded the state assurance level by 15 tons, DR1's share of the penalty is 25 percent of the total penalty, or 8 allowances (25 percent of 30).

FIGURE VII.E–1—ASSURANCE PROVISION ALLOWANCE SURRENDER EXAMPLE

	Allowances allocated	Allocation + share of variability	Total emissions	Emissions above allocation	Emissions above allocation + share of variability	Share of state exceedance (%)	Penalty (allowances surrendered)
DR1	60	71	75	15	4	25%	8
DR2	20	24	33	13	9	56%	17
DR3	10	12	15	5	3	19%	6
DR4	10	12	10	0	¥2	0%	¥
Total	100	118	133	33	15	100%	30

DR1, DR2, DR3, and DR4 are all in the same state.
State budget plus 18 percent variability limit is 118 tons (100 + 18 = 118).
State exceeded its assurance level by 15 tons (133¥118 = 15).
Penalty is 2 allowances per ton over the assurance level (2 × 15 = 30).
Some numbers may not add up due to rounding.

In the proposal, EPA took comment on whether assurance provisions should be implemented starting in 2012 or 2014. While a number of commenters supported the proposal to start in 2014, EPA received several comments making the case that starting assurance provisions in 2012 would be more compatible with the Court's opinion in *North Carolina,* which emphasized EPA's obligation to require elimination of emissions within the states that significantly contribute to nonattainment or interfere with maintenance. In this final rule, EPA makes the assurance provisions effective starting in 2012 because this approach provides even further assurance, consistent with *North Carolina,* that each state's prohibited emissions will be eliminated from the start of the Transport Rule trading programs.

F. Penalties

Under the final Transport Rule FIPs (like under the proposed rule), the owners and operators of each covered source must hold, as of the allowance transfer deadline, an allowance for each ton of SO_2 or NO_X emitted by the source and are subject to penalties if they fail to comply with this allowance-holding requirement.

In particular, the owners and operators must hold in the source's compliance account in the Allowance Management System enough allowances issued for the respective Transport Rule annual trading program (SO_2 Group 1, SO_2 Group 2, or annual NO_X program) to cover the annual emissions of the relevant pollutant from all covered units at the source. The allowances must have been issued for the year in which the emissions occurred or a prior year. If the owners and operators fail to meet this allowance-holding requirement, they must provide—for deduction by the Administrator from the source's compliance account—one allowance as an offset, and one allowance as an excess emissions penalty, for each ton of emissions (*i.e.,* excess emissions) in excess of the amount of allowances held. The allowances surrendered for the excess emissions penalty must be allocated for the control period in the year immediately following the year when the excess emissions occurred or for a control period in any prior year. The offset and the excess emissions penalty are automatic requirements in that they must be met without any further action by EPA (*e.g.,* any additional proceedings) regardless of the reason for the occurrence of the excess emissions. In addition, each ton of excess emissions, as well as each day in the averaging period (*i.e.,* the control period of one calendar year), constitute a violation of the CAA, and the maximum discretionary civil penalty is $25,000 (inflation-adjusted to $37,500 for 2010) per violation under CAA section 113. This means that, if a source has emissions in excess of allowances held for the source as of the allowance transfer deadline for a control period, the number of tons of excess emissions multiplied by the total number of days in that control period and multiplied by $25,000 (inflation adjusted) equals the maximum discretionary civil penalty for that occurrence of excess emissions.

For the ozone-season NO_X trading program, the same provisions apply as for an annual program, except that the averaging period (*i.e.,* the control period) is the ozone season, not a calendar year. Consequently, the relevant emissions are for an ozone season, the allowances usable to meet the allowance-holding requirement are allowances issued for Transport Rule ozone-season NO_X trading program for the ozone season involved or a prior ozone season, and the number of days used in calculating the maximum civil penalty is the number in the ozone season.

Commenters expressed concern that the proposed FIPs expressly stated that, for purposes of determining the maximum discretionary civil penalty for failure to meet the allowance-holding requirement, each ton of emissions lacking a held allowance would be a violation and each day in the averaging period involved would be a violation. Some commenters compared the proposed penalty provisions for excess emissions with the excess emissions penalty provisions under the Acid Rain Program and claimed that the proposed penalty provisions differed from the Acid Rain Program provisions and were excessive.

In fact, however, the final FIP provisions concerning discretionary civil penalties are essentially the same as those under the Acid Rain Program, as well as those under the NO_X Budget Trading Program and the CAIR trading programs. In particular, the Acid Rain Program regulations state that each ton of SO_2 excess emissions constitutes ''a separate violation'' of the CAA. 40 CFR 72.9(c)(2). Moreover, while the Acid Rain Program regulations do not expressly address that each day in the averaging period (*i.e.,* a calendar year control period under the Acid Rain Program) constitutes a separate violation when a unit has excess emissions for the calendar year, the courts have addressed this question. In decisions applying the discretionary civil penalty provisions in section 309(d) of the Clean Water Act, which are analogous to the civil penalty provisions in CAA section 113, the courts have interpreted the provisions to mean that, when a source violates the emission limitation for a multi-day control period, the source has a violation for each day in the control period, as well as for each ton of excess emissions on each such day. *See, e.g., Chesapeake Bay Foun.* v. *Gwaltney of Smithfield,* 791 F.2d 304, 313–15 (4th Cir. 1986), *Atlantic States Legal Foun.* v. *Tyson Foods,* 897 F.2d 1128, 1139–40 (11th Cir. 1990), and *U.S.* v. *Allegheny Ludlum Corp.,* 366 F.3d 164, 169 (3d. Cir. 2004). As noted by the courts, the treatment of each ton and each day as a separate violation is used for purposes of setting the maximum discretionary civil penalty. Because CAA section 113 sets the maximum civil penalty, EPA, of course, has the discretion to tailor the penalty amount that it seeks in any specific occurrence of excess emissions to reflect the circumstances of that excess emission occurrence. *See* 42 U.S.C. 7413(b) (stating that the Administrator may commence a civil action ''to assess and recover a civil penalty of not more than $25,000 per day for each violation''). Moreover, when a district court imposes a civil penalty, the court ''retains discretion to assess a penalty much smaller than the maximum, as the situation requires.'' *Chesapeake Bay,* 791 F.2d at 316. In addition, the Acid Rain Program regulations state that any allowance deduction, excess emission penalty, or interest under the Acid Rain Program regulations ''shall not affect liability'' of the owners and operators ''for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the [CAA],'' including under CAA section 113 providing for discretionary civil penalties. 40 CFR 77.1(b). In summary, under the Acid Rain Program, each ton of excess emissions and each day in the averaging period (*i.e.,* the calendar year) constitute a violation, the resulting number of violations times $2,000 is the maximum civil penalty for violating owners and operators, and EPA has the discretion to impose a civil penalty at or below such maximum, in addition to the automatic requirement to surrender one allowance and pay $2,000 (inflation adjusted) for each ton of excess emissions.

The final FIPs take an analogous approach to that under the Acid Rain Program. Specifically, the final FIPs state both that each ton of excess emissions is a violation of the CAA and that each day in the averaging period (*i.e.,* a calendar year under the annual programs and the ozone season under the ozone-season program) is a violation. Moreover, the imposition of civil penalties at or below the maximum amount resulting from the maximum penalty calculation is in addition to the automatic allowance surrender and penalty totaling 2 allowances per ton of excess emissions. Thus, commenters' assertion that the approach in the final FIPs is inconsistent with the approach in the Acid Rain Program is incorrect. Moreover, EPA has taken this same general approach in two other trading programs (*i.e.,* the NO_X Budget Trading Program and the CAIR trading programs), whose regulations explicitly state that each ton and each day of the averaging period constitute a violation. *See* 40 CFR 96.54(d)(3) (NO_X Budget Trading Program); and 40 CFR 96.106(d) (CAIR).

In any event, EPA maintains that the approach of treating each excess emission ton and each day in the averaging period as a violation for purposes of calculating the maximum discretionary civil penalty is reasonable. Some commenters suggested that only the days on which a source's cumulative control period emissions exceed the amount of allowances that the source then holds for that control period should be treated as a violation. However, this suggested approach makes little sense in the context of the Transport Rule trading programs.

In order to provide owners and operators compliance flexibility, the Transport Rule trading programs do not require source owners and operators to hold any amount of allowances to cover emissions until the allowance transfer deadline, no matter what the source's cumulative control period emissions are before that deadline. The commenters' approach of comparing—each day, cumulative emissions and allowances held—for purposes of calculating maximum civil penalties would be inconsistent with the flexibility that EPA intends to provide owners and operators. For example, under the commenters' suggested approach, owners and operators that buy or sell allowances in the allowance market or hold allowances in a company-wide account, do not transfer allowances into their source's compliance account until just before the allowance transfer deadline, and end up with some excess emissions for the calendar year would

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face a significantly higher maximum civil penalty than owners and operators that every day increase the amount of allowances held in their source's compliance account as the source's cumulative emissions increase and end up with the same amount of excess emissions for the calendar year. In short, the commenters' approach would penalize owners and operators that use some of the compliance flexibility that the trading programs are intended to provide.

EPA also maintains that it is reasonable to both impose the automatic allowance surrender and penalty provisions and to retain the discretion to impose civil penalties for the same occurrence of excess emissions. This approach encourages compliance with the allowance-holding requirement by ensuring that violating owners and operators are penalized automatically (*i.e.,* without any further administrative or judicial proceedings, except for appeals) and that EPA can seek additional penalties where the circumstances warrant discretionary civil penalties. In fact, the Acid Rain Program, for which CAA Title IV mandated this approach, has achieved a very high level of compliance with the requirement to hold allowances covering SO_2 emissions and therefore resulted in major reductions in utility SO_2 emissions. *See* 42 U.S.C.7651j(a). Similarly, the NO_X Budget Trading Program and CAIR trading programs, which took the same approach, also have achieved very high compliance levels and major utility emission reductions.

EPA notes that, in calculating maximum civil penalties when owners and operators fail to hold allowances required under the assurance provisions in the final FIPs, EPA takes a similar approach in determining the number of violations. Each ton for which an allowance is not held as required and each day in the control period involved constitute a violation of the CAA. As discussed elsewhere in this preamble, EPA believes that this calculation approach is also reasonable in the context of the assurance provisions and that taking an approach like the commenters' suggested approach described above would be inconsistent with some of the flexibility that the Transport Rule trading programs are intended to provide.

G. Allowance Management System

The final Transport Rule trading programs, like the proposed preferred remedy, utilize EPA's allowance management system (AMS), which currently supports allowance surrender, transfer, and tracking activity under the Acid Rain Program and CAIR. EPA received no adverse comment on this aspect of the proposed rule.

The primary role of AMS is to provide an efficient, automated means for covered sources to comply and for EPA to determine whether covered sources are complying, with the emissions-related provisions of the Transport Rule trading programs. As was proposed, each of the final SO_2 trading programs and final NO_X trading programs is separately handled in the AMS, which is used to track Transport Rule trading program SO_2 and NO_X allowances held by covered sources, as well as such allowances held by other entities or individuals.

In addition, the AMS tracks: The allocation of all SO_2 and NO_X allowances; holdings of SO_2 and NO_X allowances in compliance accounts (*i.e.,* accounts for individual covered sources), general accounts (*i.e.,* accounts for other entities such as companies and brokers), and assurance accounts (*i.e.,* accounts for allowance surrender by owners and operators of groups of sources and units with common designated representatives under the assurance provisions); deduction of SO_2 and NO_X allowances for compliance purposes (including deductions from assurance accounts where necessary); and transfers of allowances between accounts. The AMS also allows the public to see whether each source is in compliance and provides information to the allowance market and the public in general, including information on ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

H. Emissions Monitoring and Reporting

Under the proposed rule, units subject to the Transport Rule trading programs would monitor and report NO_X and SO_2 mass emissions in accordance with 40 CFR part 75, as incorporated in the proposed rule, and with certain other specified requirements, such as compliance deadlines.

In the final rule, like the proposed rule, covered units must comply with emissions monitoring and reporting requirements that are largely incorporated from Part 75 monitoring and reporting requirements.

Under the final rule and under Part 75, a unit has several options for monitoring and reporting, namely the use of: a CEMS; an excepted monitoring methodology (NO_X mass monitoring for certain peaking units and SO_2 mass monitoring for certain oil- and gas-fired units); low mass emissions monitoring for certain non-coal-fired, low emitting units; or an alternative monitoring system approved by the Administrator through a petition process. In addition, the Administrator can approve petitions for alternatives to Transport Rule and Part 75 monitoring, recordkeeping, and reporting requirements.

Further, the final rule and Part 75 specify that each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits (RATAs) and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied and result in a conservative estimate of emissions for the period involved.

In addition, the final rule and Part 75 require electronic submission, to the Administrator and in a format prescribed by the Administrator, of a quarterly emissions report. The report must contain all of the data required concerning NO_X annual and ozone-season and SO_2 annual emissions.

Most Transport Rule units are in states subject to CAIR and are already monitoring and reporting NO_X and/or SO_2 under CAIR and the Acid Rain Program, which programs also use Part 75 monitoring and reporting. Units under the Transport Rule annual trading programs and in states subject to CAIR generally have no changes to their monitoring and reporting requirements. These units must continue to monitor and submit reports on a year-round basis as they have under CAIR. Therefore, units in the following states must monitor and report both SO_2 and NO_X year-round under the Transport Rule: Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia and Wisconsin.

Some states (Kansas, Minnesota, and Nebraska) subject to the Transport Rule annual trading programs were not subject to CAIR. Transport Rule units in those states must meet monitoring and reporting requirements that are new except to the extent the units were subject to Part 75 under some other program (such as the Acid Rain Program).

Further, some states (Florida, Louisiana, and Mississippi) subject to the Transport Rule ozone-season trading program but not the Transport Rule annual trading programs were subject to the annual and ozone-season trading programs under CAIR. Transport Rule

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units in those states must continue to monitor and report in accordance with Part 75 but have the option of monitoring and reporting on a year-round or ozone-season-only basis.

In addition, one state (Arkansas) subject to the Transport Rule ozone-season trading program but not to the Transport Rule annual trading program was similarly subject to only the ozone-season trading program in CAIR. Transport Rule units in that state continue to have the option of monitoring and reporting NO_X on a year-round or ozone-season-only basis.

Finally, some states (Connecticut, Delaware, District of Columbia, and Massachusetts) that were subject to CAIR are not subject to the Transport Rule. Electric generating units in those states must continue to meet monitoring and reporting requirements only to the extent the units are subject to Part 75 under some other program (such as the Acid Rain Program or a state adopted program requiring such monitoring and reporting).

EPA is finalizing requirements for existing Transport Rule units in states covered by the Transport Rule annual trading programs to monitor and report SO_2 and NO_X emissions by January 1, 2012 programs and for existing Transport Rule units in states covered by the Transport Rule ozone-season trading program to monitor NO_X emissions by May 1, 2012. The use of Part 75 certified monitoring methodologies is required in both cases. As discussed previously, most covered existing units will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under Part 75 as they have under CAIR. Existing units that have not been subject to Part 75 monitoring and reporting requirements in the past have less than 1 year to install, certify, and operate the required monitoring systems. EPA believes that these units will be able to comply with this requirement because the monitoring equipment needed is not extensive or is largely in place already for the purpose of meeting other requirements. Quality assurance and reporting provisions and data system upgrades may be necessary, but EPA believes that there is sufficient time to accomplish this by the deadline for existing units in the final rule.

In the proposed rule, the compliance deadline for installing, certifying, and operating the required monitoring systems at new units was based upon the date of commencement of commercial operation. A new unit would have to install and certify its monitoring system within 180 days of the commencement of commercial operation. The final rule adopts this deadline, which is consistent with the approach recently adopted in Part 75 under the Acid Rain Program. *See* 76 FR 17288, 17289 (March 28, 2011).

Using this deadline (rather than a deadline, used previously in Part 75, of the earlier of the unit's 90th operating day or 180 days after the unit's commencement of commercial operation) ensures that new units have sufficient time to complete installation and certification of monitoring systems and facilitates units' compliance. Because of unit shakedown problems, some new units have had difficulty meeting a deadline earlier than 180 days after commencement of commercial operation. Further, using this deadline facilitates owners' and operators, and EPA's, ability to track important dates related to monitoring, reporting, and allowance holding. Under the final rule, the requirement that a unit hold enough allowances to cover its emissions starts on the later of the commencement of the Transport Rule trading program involved or the deadline for installation and certification of the monitoring system. Having a simple, easily determined deadline (180 days after the commencement of commercial operation) makes it easier for owners and operators and EPA to determine when allowance-holding requirements begin, as well as when monitoring and reporting requirements begin. In contrast, using a deadline involving determination of a unit's 90th operating day required keeping track of any days on which the unit did not operate (*e.g.*, due to problems associated with shakedown of the unit). EPA found that owners and operators have had more difficulty reporting the 90th operating day than in reporting the commencement of commercial operation, and once the latter date is reported, EPA can independently determine the 180th calendar day after the reported date.

I. Permitting

1. Title V Permitting

The final Transport Rule (like the proposed rule) does not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing Title V, 40 CFR Parts 70 and 71.[84] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable State Implementation Plan. CAA §§ 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements,'' that must be addressed in title V permits are defined in the Title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

EPA anticipates that, given the nature of the units covered by the final Transport Rule, most of the sources at which they are located are already or will be subject to Title V permitting requirements. For sources subject to Title V, the requirements applicable to them under the final FIPs will be ''applicable requirements'' under Title V and therefore will need to be addressed in the Title V permits. For example, requirements under the final FIPs concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the assurance provisions, and liability will be ''applicable requirements'' to be addressed in the permits.

The Title V permits program includes, among other things, provisions for permit applications, permit content, and permit revisions that will address the applicable requirements under the final FIPs in a manner that will provide the flexibility necessary to implement market-based programs such as the Transport Rule trading programs. For example, the Title V regulations provide that a permit issued under Title V must include, for any ''approved * * * emissions trading and other similar programs or processes'' applicable to the source, a provision stating that no permit revision is required ''for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with this provision in the Title V regulations, the Transport Rule trading program regulations include a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. Consistent with the Title V regulations, this provision will also be included in each Title V permit for a covered source. As a result, allowances can be traded (or allocated, held, or deducted) under the final FIPs without a revision of the Title V permit of any of the sources involved.

As a further example of flexibility under Title V, the Title V regulations allow the use of the minor permit modification procedures for permit modifications ''involving the use of economic incentives, marketable permits, emissions trading, and other

[84] Part 70 addresses requirements for state Title V programs, and Part 71 governs the federal Title V program.

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similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA.'' 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). The final FIPs set forth in detail, and reference relevant provisions in Part 75 concerning, the approaches that are available for covered units to use for monitoring and reporting emissions (*i.e.,* approaches using a continuous emission monitoring system, an excepted monitoring system under appendices D and E to Part 75, a low mass emissions excepted monitoring methodology under § 75.19, or an alternative monitoring system under subpart E of Part 75). The final FIPs also require unit owners and operators to submit monitoring system certification applications (or, for alternative monitoring systems, petitions) to EPA establishing the monitoring and reporting approach actually to be used by the unit and allow owners and operators to submit petitions for alternatives to any specific monitoring and reporting requirement. These applications and petitions are subject to EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants, and EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are to be posted on EPA's Web site. Moreover, EPA intends that each covered unit's Title V permit will include a description of the general approach that the covered unit is required to use for monitoring and reporting emissions and that the description will reference the relevant sections of the Transport Rule trading program regulations and Part 75 and will state that the requirements may be modified through EPA approval of petitions for alternatives to specific requirements. Finally, consistent with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of the Title V regulations, the final FIPs provide that a description of the general monitoring and reporting approach for a covered unit can be added to, or an existing description of a unit's general monitoring and reporting approach can be changed, in a Title V permit, using minor permit modification procedures, provided that the approach being described in the changed or new general description and the requirements applicable to that approach are already incorporated elsewhere in the permit. As a result, minor permit modification procedures can be used to revise a covered unit's Title V permit to be consistent with the monitoring and reporting approach, or any changes in the approach, allowed for the unit by EPA through the monitoring system certification or petition process under the Transport Rule trading programs.

As new applicable requirements under Title V, the requirements for covered units under the final FIPs will be incorporated into covered sources' existing Title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 40 CFR 71.7(f)) or the permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[85] In contrast to the approach in CAIR of imposing permitting requirements and deadlines independent of those under Title V, the approach to permitting under the final FIPS of imposing no independent permitting requirements should reduce the burden on sources already required to be permitted under Title V and on permitting authorities. For sources newly subject to Title V that will also be covered sources under the final FIPs, the initial Title V permit issued pursuant to 40 CFR 70.7(a) will address the final FIP requirements.

In order to ensure that covered sources' Title V permit provisions concerning the final FIPs will reflect the Transport Rule trading program requirements and flexibilities properly and in a manner consistent from permit to permit, EPA intends to issue guidance to assist permitting authorities. This guidance would include information on permit issuance and permit modification requirements, as well as a permit content template that will identify the applicable requirements under the applicable Transport Rule trading program and thereby ensure that they will be correctly and comprehensively reflected in each permit in a manner that will reduce the burden on sources and permitting authorities related to the issuance of the permit and will reduce the need for permit revisions.

2. *New Source Review*

a. Background

EPA recognizes that, following the vacatur of the new source review (NSR) pollution control project exemption in *New York* v. *EPA, 413 F.3d 3, 40–41 (D.C. Cir. 2005),* pollution control projects, including pollution control projects constructed to comply with this rule, have the potential to trigger NSR permitting.

This issue was previously addressed in the context of CAIR. On December 20, 2005, the EPA agreed to reconsider one specific aspect of CAIR. In that notice, EPA granted reconsideration and sought comment on the potential impact of the opinion in *New York* v. *EPA,* which vacated the previously existing NSR exemption for certain environmentally beneficial pollution control projects. For this reconsideration, EPA conducted an analysis which showed that the court decision did not impact the CAIR analyses. Details of this analysis can be found in a technical support document which is available on EPA's Web site at: *http://epa.gov/cair/pdfs/0053-2263.pdf*

Because GHG emissions were not considered by EPA to be air pollutants within the meaning of the CAA at the time of CAIR, GHG emissions were not addressed in the 2005 analysis. GHG requirements related to the component of NSR concerning the Prevention of Significant Deterioration (''PSD'') program are addressed in EPA's ''Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs,'' 75 FR 17004 (April 2, 2010), and ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule,'' 75 FR (June 3, 2010) (''Tailoring Rule''). Generally, as discussed in those actions, major stationary sources will be required to address GHG emissions as part of the PSD program if these sources emit GHG in amounts that equal or exceed the thresholds in the Tailoring Rule. Major sources that undergo a modification, including the addition of pollution control equipment, will trigger PSD requirements for their emissions of GHG if such emissions increase by at least 75,000 [86] tons per year of CO_2 equivalent (CO_2e).

b. Proposed Rule

In the proposed rule, EPA presented the following conclusions:

(1) The 2005 analysis remains current and relevant for all pollutants except for GHG, and it shows that NSR requirements would not significantly impact the construction of controls that

[85] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to a covered source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

[86] We note that, for sources that are modifying and are not subject to PSD for emissions of a non-GHG pollutant, in order to be subject to PSD for GHGs the source must not only have an emissions increase of 75,000 TPY CO_2e, but must also have a PTE of at least 100,000 TPY CO_2e and 100 TPY mass GHG. *See* 40 CFR 52.21(b)(49)(v)(b). However, since it is reasonable to assume that all sources that are potentially subject to the Transport Rule will have a PTE of at least 100,000 TPY CO_2e and 100 TPY, for the purposes of discussions in this section we will only note the requirement to have an emissions increase of 75,000 TPY CO_2e.

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are installed to comply with the proposed Transport Rule.

(2) It is very unlikely that pollution control projects would cause GHG increases that would exceed the 75,000 tons per year threshold.

Consistent with these proposed conclusions, EPA also concluded that there would be no significant impacts from NSR for any pollution control projects resulting from the proposed rule such as low-NO_X burners, SO_2 scrubbers, or SCR. EPA requested comment on this issue.

c. Public Comments

EPA received a number of comments on the NSR issue, which can be divided into four types of comments: (1) Comments related to GHGs, (2) comments related to sulfuric acid mist, (3) comments related to CO emission increases from low-NO_X burners, and (4) suggested changes to the EPA rules.

Greenhouse Gases. A number of commenters recommended that EPA should document and substantiate its conclusion that greenhouse gases would be unlikely to trigger NSR requirements. Other commenters suggested that some units installing a FGD scrubber could exceed the 75,000 ton threshold for GHGs in the Tailoring Rule by emitting CO_2 produced from the chemical reaction of SO_2 with limestone. Commenters also suggested that NSR applicability for GHGs would also need to consider that an FGD would consume 1–3 percent of a scrubbed unit's generation, referred to as ''parasitic load,'' which (all else held equal) lowers that unit's net generation.[87] Commenters argued that any post-retrofit increase in generation to offset that ''parasitic load'' could lead to GHG increases potentially exceeding the 75,000 ton threshold.

Sulfuric Acid Mist. Two commenters noted that use of high sulfur fuels, in combination with SCR, can lead to increases in sulfuric acid mist, a pollutant regulated under NSR. One of these commenters noted that reagent injection was necessary to avoid triggering NSR for sulfuric acid mist when their SCR was installed.

Carbon Monoxide (CO). One commenter believed that EPA's 2005 analysis may not be adequate as it related to carbon monoxide emission increases that result from installation of low-NO_X burners. The commenter noted EPA's statement in the 2005 analysis that read as follows: ''Since the NO_X removal efficiencies used in EPA's analysis are not aggressive, it is believed that the units installing combustion controls can opt for moderate levels of overfire air flow rates and still achieve the NO_X reduction levels projected in EPA's analysis, without causing significant increases in the CO and unburned carbon emissions.'' The commenter suggested that the transport rule NO_X may be more aggressive than CAIR and thus EPA should conduct a review to determine whether EPA retains the same conclusion regarding CO emissions.

Recommended Rule Changes. Some commenters suggested changes to EPA rules to address their concerns that control equipment installed as a result of the Transport Rule could trigger NSR. Some commenters suggested that EPA craft an exclusion from NSR in the Transport Rule. One of these commenters suggested that EPA could do this by: (1) Providing special definition of baseline actual emissions; (2) a causation determination specifically tied to the Transport Rule; or (3) interpret the term ''stationary source'' in CAA 110(a)(4) in a way that doesn't impede Transport Rule compliance.

Other commenters expressed the concern that if NSR is triggered, the proposed Transport Rule did not allow enough time for compliance for sources needing to install control equipment. These commenters recommend that EPA should waive Transport Rule requirements or provide extra allowances until NSR review is complete.

d. Final Rule and Responses to Comments

Greenhouse Gases. EPA has carefully reviewed relevant data in assessing the comments suggesting that NSR permitting would likely be triggered for facilities installing FGD scrubbers to comply with this rule. EPA believes that sources installing FGD to comply with the Transport Rule can achieve those installations without triggering NSR.

EPA notes that its forecast of the number and extent of FGD scrubber installations substantially decreased since the time of proposal. For the proposed rule, EPA modeled 14 GW of FGD retrofit installations by 2014. For the final rule, EPA models a total of 5.7 GW of wet FGD installations from 7 units at 5 plants.

There are two factors associated with wet FGD scrubbers that commenters suggested individually or in combination could lead to increases above the 75,000 tons per year threshold in the Tailoring Rule. The first is the CO_2 chemically produced from the reaction of SO_2 with limestone in wet FGD scrubbers. The second is that owners or operators of the affected units may desire to increase coal usage after the retrofit is made to offset the ''parasitic load'' that is consumed on-site in order to operate the scrubber.

With respect to chemically produced CO_2, EPA concludes that only in very limited circumstances when installation of a scrubber is coupled with a change to considerably higher sulfur coal could installation of a wet limestone scrubber be associated with a more than 75,000 ton increase in CO_2 emissions. EPA finds this possibility unlikely to occur. For example, EPA's acid rain emissions reporting system shows that the plant with the greatest emissions from unscrubbed units in 2009 emitted about 103,000 tons of SO_2 from those units. If this plant installed a wet limestone scrubber assumed to reduce those SO_2 emissions by 96 percent, EPA calculates that chemically produced CO_2 could increase emissions by:

$$103{,}000 \times (0.96) \times (44/64) = 67{,}980 \text{ tons } CO_2.$$ [88]

Therefore, EPA finds that all currently uncontrolled units are technically capable of retrofitting with wet FGD without chemically produced CO_2 increases leading to a triggering of NSR. In limited circumstances, an owner or operator may elect to switch fuels to a significantly higher-sulfur coal subsequent to FGD installation and may risk an increase in chemically produced CO_2 emissions that would trigger NSR, but such a decision is not necessary in order to successfully install and operate the scrubber as a strategy for compliance with Transport Rule requirements.

With respect to the ''parasitic load'' issue, EPA estimates that today's wet FGD retrofit technology would consume typically about 1.7 percent of on-site generation.[89] If a facility made no other changes to its operation other than installing an FGD retrofit, that facility's CO_2 emissions from fuel combustion would remain constant. It is possible, however, that a source's owner or operator may elect to increase coal usage by some amount after retrofitting FGD, if for example the owner or operator desires to increase net generation after retrofitting. Under NSR, any such source would be able to

[87] ''Net generation'' refers to total generation minus the amount of power consumed on-site for various purposes, including operation of pollution control equipment.

[88] The factor 44/64 reflects the relative molecular weight of CO_2 and SO_2, respectively. A wet FGD's removal of one ton of SO_2 involves a chemical reaction that releases the equivalent molecular weight of CO_2 (thus equaling 44/64 of a ton of CO_2 emissions).

[89] Documentation Supplement for EPA Base Case v.4.10_FTransport—Updates for Final Transport Rule.

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compare such a CO_2 emissions increase against the highest average annual emissions in any consecutive 24-month period from a 5-year historic baseline. Therefore, a unit retrofitting a scrubber under the Transport Rule may be able to increase its CO_2 emissions by more than 75,000 tons without triggering NSR if that increase would register as less than 75,000 tons against a higher emissions level in the aforementioned NSR baseline.

EPA also notes that scrubber installations provide facilities with the opportunity to make other capital improvements at the unit on which the scrubber is installed to improve the efficiency of boilers, steam turbines, motors, other auxiliary equipment, and plant control systems. Such improvements could allow a retrofitting unit to lower its CO_2 output rate such that a subsequent decision to increase net generation may not result in increased coal use, or may limit any CO_2 emission increase to less than the 75,000 tons per year threshold for triggering NSR.

As discussed in section VII.C, EPA notes that the Transport Rule does not mandate any specific control activity, including scrubber retrofitting, as a compliance strategy for units within a state to meet that state's SO_2 budget. As demonstrated by EPA's ''no FGD'' sensitivity analysis described in VII.C, covered sources within the Group 1 states are capable of meeting their emission reduction obligations through a variety of emission reduction strategies even if no unit is able to complete a scrubber installation by 2014. Therefore, EPA does not believe that NSR permitting presents an obstacle in any way to Transport Rule compliance, even if a given unit retrofitting with FGD triggers NSR for CO_2.

For some plants, EPA's IPM modeling forecasts installation and operation of dry sorbent injection (DSI) systems. EPA does not believe any of these systems would result in CO_2 emission increases above the 75,000 ton threshold. Moreover, given the relatively short construction schedule for DSI systems, EPA believes that if any of the plants did require NSR permitting, installation of DSI could still be accomplished by 2014.

In summary, EPA believes that the operators of plants projected to install scrubbers for Transport Rule SO_2 reductions could readily develop workable compliance strategies whether or not such an installation would trigger NSR. Plant owners could readily develop strategies to avoid emission increases that would trigger NSR, including but not limited to alternative SO_2 reduction strategies or technologies, efficiency improvements, or the ability to adjust net electricity generation to prevent a 75,000 ton increase in CO_2 emissions. EPA believes that projected scrubber installations under the Transport Rule are broadly unlikely to trigger NSR, but even in the limited conditions where such a triggering may occur, the NSR permitting process would not infringe on a state's ability to comply with its budgets under the Transport Rule. (*See* section VII.C for more details on EPA's analysis of a ''no FGD'' sensitivity supporting these points.)

Sulfuric Acid Mist. EPA continues to conclude that, consistent with the 2005 TSD, sulfuric acid mist increases due to compliance with this rule are very unlikely to trigger NSR permitting. Such increases are most commonly seen from installation of SCR units on facilities with relatively high sulfur coal. However, as acknowledged by one of the commenters, engineering solutions have been developed to prevent such increases, and EPA believes that facility owners would take this into account in designing such an SCR system. Moreover, EPA's IPM modeling of the NO_X budgets in the final rule suggests that no new SCR units will result from the final rule.

Carbon Monoxide. EPA concludes that any NSR permitting required due to CO increases associated with NO_X controls should not hinder the ability of sources to comply with Transport Rule requirements. For states that were included in the CAIR for either ozone, $PM_{2.5}$, or both, EPA finds no evidence to suggest that the NO_X control requirements of the Transport Rule would require more aggressive controls triggering NSR. As EPA's baseline analysis acknowledges, many sources in these states installed NO_X controls to comply with CAIR. In addition, their historic emissions reflect operation of these controls and there is no evidence to suggest that the Transport Rule will require sources to operate these controls more aggressively, thereby increasing CO emissions above the relevant threshold and triggering NSR. In a few states that were not covered by CAIR, a limited number of facilities may install new combustion controls (such as low-NO_X burners, overfire air, or other combustion controls or upgrades) as a result of the Transport Rule. EPA expects relatively few such installations, and believes that NSR permitting, if required, is not an obstacle to compliance with the rule. First, EPA believes that NSR permitting should be relatively straightforward for these installations and that the BACT determination for CO will be very straightforward. EPA expects a relatively short time period for permitting, and as discussed later, EPA is planning to initiate actions that will further expedite any required permitting.

Second, EPA notes that the rule achieves reductions through a trading program rather than direct control requirements. Accordingly, even if a few installations do not have controls in place at the very beginning of the compliance period, this should not hinder the ability of states to meet their ozone-season NO_X budgets. Covered sources have a suite of NO_X pollution control strategies and technologies available to them, including coal selection, selective non-catalytic reduction, gas re-burn, low-NO_X burner and overfire air installations or upgrades, and neural network optimization of combustion controls operation. Sources may consider all of these technologies and strategies, which can be designed and operated so as to minimize CO emission increases that may otherwise trigger NSR. EPA also notes that during the downtime for installation of the construction controls, there would be no NO_X emissions, and thus the source's allowance holding requirements would also be lower for that period.

Recommended Rule Changes. EPA disagrees with commenters who suggested rule changes, either to the NSR program or to this rule, to account for installations triggering NSR. As noted above, EPA concludes that NSR would be triggered at most for just a few of the projected control installations. EPA believes, however, that even if required these NSR permits would likely be issued in a timely manner given the overall environmental benefits resulting from the control equipment installation. In addition, this rule's requirements are based on a flexible trading approach rather than a direct control approach. Accordingly, if this affect occurs for only a few installations, EPA believes that any extra emissions that occur during the relatively short time needed to obtain an NSR permit could be accommodated within the overall trading system.

Expediting Permitting. In the limited circumstances where pollution control installations under the Transport Rule may trigger NSR, we also note that an expedited permitting process can occur with sufficient time to obtain permits and achieve emission reductions under the Transport Rule programs. For this reason, we strongly encourage permitting authorities to expedite

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permitting for any such projects, which are likely to be very limited in number. To ensure that the permitting decisions are expedited, separate from this rulemaking EPA will provide assistance and guidance in order to expedite issuance of any such permits. For example, we are considering assistance that would serve to expedite BACT reviews or required air quality analysis. EPA requests early notification of any specific cases where such guidance and assistance may be needed.

J. How the Program Structure Is Consistent With Judicial Opinions Interpreting the Clean Air Act

The air quality-assured trading programs established by this rule eliminate all of the emissions that EPA has identified as significantly contributing to downwind nonattainment or interference with maintenance [90] in a manner that is consistent with section 110(a)(2)(D)(i) of the CAA as interpreted by the DC Circuit in *North Carolina,* 531 F.3d 896. The FIPs finalized in this action require sources to participate in air quality-assured interstate emission trading programs that include provisions to ensure that no state's emissions exceed that state's budget with variability limit. These assurance provisions, combined with the requirement that all sources hold emission allowances sufficient to cover their emissions, effectuate the requirement that emission reductions occur within the state. *See* 42 U.S.C. 7410(a)(1)(2)(D).

The state budgets developed in this rule represent an estimate of the emissions that will remain in a given state after the elimination of all emissions in that state that EPA has determined must be prohibited pursuant to section 110(a)(2)(D)(i)(I). However, for the reasons explained above, the amount of emissions that remain after the requirements of 110(a)(2)(D)(i)(I) are satisfied may vary. EPA recognizes that shifts in generation due to, among other things, changing weather patterns, demand growth, or disruptions in electricity supply from other units can affect the amount of generation needed in a specific state and thus baseline EGU emissions from that state. Because a state's significant contribution to nonattainment or interference with maintenance is defined by EPA as all emissions that can be eliminated for a specific cost (as explained above, using air quality considerations to identify this cost threshold), and because EGU baseline emissions are variable, the amount of emissions remaining in a state after all significant contribution or interference with maintenance is eliminated is also variable. In other words, EGU emissions in a state whose sources have installed all controls and taken all measures necessary to eliminate its significant contribution to nonattainment or interference with maintenance could exceed the state budget without variability.

For this reason, EPA determined that it is appropriate for the program to recognize the inherent variability in state EGU emissions. The program does so by identifying a variability range for each state in the program. The assurance provisions in the program, in turn, limit a state's emissions to the state's budget with variability limit.

In addition, the requirement that all sources hold emission allowances sufficient to cover their emissions (and the fact that the total number of emission allowances allocated will be equal to the sum of all state budgets without variability) ensures that the use of variability limits both takes into account the inherent variability of baseline EGU emissions in individual states (*i.e.,* the variability of total state EGU emissions before the elimination of significant contribution or interference with maintenance) and recognizes that this variability is not as great in a larger region. The variability of emissions across a larger region is not as large as the variability of emissions in a single state for several reasons. Increased EGU emissions in one state in one control period often are offset by reduced EGU emissions in another state within the control region in the same control period. In a larger region that includes multiple states, factors that affect electricity generation, and thus EGU emission levels, are more likely to vary significantly within the region so that resulting emission changes in different parts of the region are more likely to offset each other. For example, a broad region can encompass states with differing weather patterns, with the result that increased electricity demand and emissions due to weather in one state may be offset by decreased demand and emissions due to weather in another state. By further example, a broad region can encompass states with differing types of industrial and commercial electricity end-users, with the result that changes in electricity demand and emissions among the states due to the effect of economic changes on industrial and commercial companies may be offsetting. Similarly, because states in a broad region may vary in their degree of dependence on fossil-fuel-based electric generation, the impact of an outage of non-fossil-fuel-based generation (*e.g.,* a nuclear plant) in one state may have a very different impact in that state than on other states in the region. Thus, EPA does not believe it is necessary to allow total regional allowance allocations for the states covered by a given trading program to exceed the sum of all state budgets without variability for these states.

For these reasons, the fact that the use of state budgets with variability limits may allow limited shifting of emissions between states is not inconsistent with the court's holding that emission reductions must occur "within the state." *North Carolina,* 531 F.3d at 907. Under the FIPs, no state may emit more than its budget with variability limit and total emissions cannot exceed the sum of all state budgets without variability. This approach takes into account the inherent variability of the baseline emissions without excusing any state from eliminating its significant contribution to nonattainment or interference with maintenance. It is thus consistent with the statutory mandate of section 110(a)(2)(D)(i)(I) as interpreted by the Court.

Most commenters voiced support for a remedy option that allows some degree of interstate trading. However, one commenter argued that the structure of the preferred trading remedy that EPA proposed is legally problematic. The program, the commenter argues, provides no legal assurance that the variability margins will be used by market participants to account for variability. The commenter does not suggest a solution, but instead says, if a solution cannot be found, EPA should not allow any amount of interstate trading.

EPA disagrees with the commenter that the structure of the preferred interstate trading program is legally problematic. In *North Carolina,* the Court held that the CAIR interstate trading programs were inconsistent with section 110(a)(2)(D)(i)(I), concluding that "EPA's apportionment decisions have nothing to do with each state's 'significant contribution' " (531 F.3d at

[90] As explained in greater detail in Section VI of this notice, for each covered state, EPA has identified emissions that must be prohibited pursuant to section 110(a)(2)(D)(i)(I). In most instances, EPA has determined that elimination of such emissions is sufficient to satisfy the requirements of that section. Thus, in these instances, the budgets represent an estimate of the emissions that will remain after the elimination of all emissions in that state that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in another state. In a few limited instances, however, EPA determined that elimination of the emissions is necessary but may not be sufficient to satisfy the requirements of that section. In these instances, the budgets represent an estimate of the emissions that will remain after the elimination of all emissions that EPA, at this time, has determined must be eliminated.

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907) and that ''EPA is not exercising its section 110(a)(2)(D)(i)(I) duty unless it is promulgating a rule that achieves something measurable toward the goal of prohibiting sources 'within the State' from contributing to nonattainment or interfering with maintenance 'in any other State.' '' (531 F.3d at 908). It emphasized that ''[t]he trading program is unlawful, because it does not connect states' emission reductions to any measure of their own significant contributions. To the contrary, it relates their SO_2 reductions to their Title IV allowances. * * * The allocation of NO_X caps is similarly arbitrary because EPA distributed allowances simply in the interest of fairness.'' 531 F.3d at 930. As explained in this rule, EPA has addressed these concerns by using source specific analysis to identify each individual state's significant contribution to nonattainment and interference with maintenance, and including assurance provisions to ensure that the necessary reductions occur in each state. The Court did not go further to prohibit all interstate trading. In fact, it notes that ''after rebuilding, a somewhat similar CAIR may emerge'' (531 F.3d at 930). For all of these reasons, EPA does not believe the opinion in *North Carolina* can be read to stand for the proposition that no interstate trading can be allowed unless the specific reasons behind market participants' decisions to purchase allowances can be ascertained. Because allowance purchase decisions are likely to be based on multiple factors, which can include the desire to hedge against potential emission variability as well as to address actually occurring variability, requiring ascertainment of the specific reasons for allowance purchases would be tantamount to prohibiting all interstate trading.

Moreover, as discussed above, variability is inherent to the operation of the electric generation system and thus to emissions from this sector. In fact, variability in emissions occurs every year in every state and, like variability of year-to-year weather conditions (which is a major cause of emission variability), cannot be accurately predicted. *See* the Power Sector Variability Final Rule TSD in the docket for this rulemaking. EPA maintains that its approach of allowing state EGU emissions each year to vary by up to the historically representative, annual amount of inherent, emission variability reasonably reflects the realities of the electric generation system and is consistent with the *North Carolina* decision. In summary, the variability limits take into account inherent variability over time of emissions in each state from this sector while also ensuring that each state makes necessary emission reductions to eliminate significant contribution and interference with maintenance. EPA thus concludes that the commenter's argument that the use of variability limits allows sources ''within the state'' to avoid eliminating their significant contribution or interference with maintenance is without merit.

VIII. Economic Impacts of the Transport Rule

A. Emission Reductions

The projected impacts of this final rule as presented throughout the preamble do not reflect minor technical corrections to SO_2 budgets in three states (KY, MI, and NY) made after the impact analyses were conducted. These projections also assumed preliminary variability limits that were smaller than the variability limits finalized in this rule. EPA conducted sensitivity analysis confirming that these differences do not meaningfully alter any of the Agency's findings or conclusions based on the projected cost, benefit, and air quality impacts presented for the final Transport Rule. The results of this sensitivity analysis are presented in Appendix F in the final Transport Rule RIA.

Table VIII.A–1 presents projected power sector emissions in the base case (*i.e.,* without the Transport Rule or CAIR) compared to projected emissions with the Transport Rule in 2012 and 2014 for all covered states. Table VIII.A–2 presents 2005 historical power sector emissions compared to projected emissions with the Transport Rule in 2012 and 2014. Note that for ozone-season emissions, these tables present results from a modeling scenario that reflects ozone-season NO_X requirements in 26 states. This modeling differs from the final Transport Rule because it includes ozone-season NO_X requirements for six states (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin) that the final Transport Rule does not cover (as discussed previously, EPA is issuing a supplemental proposal to request comment on inclusion of these six states).

TABLE VIII.A–1—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSION REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASE CASE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 Base case emissions	2012 Transport rule emissions	2012 Emission reductions	2014 Base case emissions	2014 Transport rule emissions	2014 Emission reductions
SO_2	7.0	3.0	4.0	6.2	2.4	3.9
Annual NO_X	1.4	1.3	0.1	1.4	1.2	0.2
Ozone-Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

Notes: The SO_2 and annual NO_X emissions in this table reflect EGUs in the 23 states covered by this rule for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS (Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin).

The ozone-season NO_X emissions reflect EGUs in the 20 states covered by this rule for purposes of the ozone NAAQS (Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia) and the six states that would be covered for the ozone NAAQS if EPA finalizes its supplemental proposal (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin).

Tables VIII.A–3 through VIII.A–5 present projected state-level emissions with and without the Transport Rule in 2012 and 2014 from fossil-fuel-fired EGUs greater than 25 MW in covered states.

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TABLE VIII.A–2—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSION REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 Actual emissions	2012 Transport rule emissions	2012 Emission reductions from 2005	2014 Transport rule emissions	2014 Emission reductions from 2005
SO_2	8.8	3.0	5.8	2.4	6.4
Annual NO_X	2.6	1.3	1.3	1.2	1.4
Ozone-Season NO_X	0.9	0.6	0.3	0.6	0.3

Notes: The SO_2 and annual NO_X emissions in this table reflect EGUs in the 23 states covered by this rule for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS (Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin).

The ozone-season NO_X emissions reflect EGUs in the 20 states covered by this rule for purposes of the ozone NAAQS (Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia) and the six states that would be covered for the ozone NAAQS if EPA finalizes its supplemental proposal (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin).

Table VIII.A-3 - Projected State-level Annual SO_2 Emissions from Fossil-Fired Electric Generating Units Greater than 25 MW in Covered States in 2012 and 2014 in Base Case and with Transport Rule (tons)

	Base Case		Transport Rule	
	2012	2014	2012	2014
Alabama	455,503	417,009	219,067	173,231
Georgia	405,933	169,702	158,581	92,605
Illinois	485,417	137,522	209,701	128,143
Indiana	776,359	711,265	241,258	177,222
Iowa	121,663	127,354	75,003	77,931
Kansas	68,490	69,767	41,433	45,681
Kentucky	520,531	487,990	146,133	116,912
Maryland	49,942	42,926	26,630	30,368
Michigan	252,411	265,611	190,274	158,394
Minnesota	64,524	66,268	42,862	45,143
Missouri	375,771	381,939	181,662	177,359
Nebraska	70,754	71,821	65,079	70,087
New Jersey	26,346	38,857	5,518	6,243
New York	51,243	40,416	20,378	12,689
North Carolina	144,554	120,441	117,383	63,382
Ohio	871,401	831,648	230,216	150,784
Pennsylvania	493,206	507,360	250,484	123,224
South Carolina	184,045	209,538	84,435	96,589
Tennessee	324,372	284,463	96,520	64,716
Texas	445,715	452,978	244,239	266,288
Virginia	80,889	64,917	66,640	38,562
West Virginia	535,586	497,398	119,174	83,235
Wisconsin	131,199	124,862	77,505	44,139
Total	6,935,853	6,122,051	2,910,173	2,242,927

Table VIII.A-4 - Projected State-level Annual NO_X Emissions from Fossil-Fired Electric Generating Units Greater than 25 MW in Covered States in 2012 and 2014 in Base Case and with Transport Rule (tons)

	Base Case		Transport Rule	
	2012	2014	2012	2014
Alabama	82,005	74,937	73,600	68,119
Georgia	66,384	47,808	61,464	39,817
Illinois	51,969	54,661	47,635	48,533
Indiana	119,625	116,552	109,773	109,392
Iowa	42,563	44,614	36,953	38,302
Kansas	37,106	32,390	30,603	23,938
Kentucky	88,136	83,481	83,856	76,026
Maryland	16,602	17,444	15,665	17,061
Michigan	60,594	64,345	59,405	57,311
Minnesota	36,833	37,952	30,524	30,849
Missouri	53,199	54,528	51,329	48,888
Nebraska	42,985	43,410	26,488	26,552
New Jersey	7,391	7,858	7,355	7,562
New York	17,556	18,505	17,616	17,250
North Carolina	51,902	46,130	47,679	41,676
Ohio	100,420	99,389	84,679	84,126
Pennsylvania	129,125	132,299	117,612	116,994
South Carolina	34,635	37,862	33,144	35,591
Tennessee	37,674	29,256	32,984	20,490
Texas	136,124	140,788	133,406	136,638
Virginia	34,567	35,798	33,244	34,891
West Virginia	61,792	64,182	55,808	53,335
Wisconsin	36,701	36,904	30,643	29,688
Total	1,345,888	1,321,092	1,221,466	1,163,027

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Table VIII.A-5 – Projected State-level Ozone-Season NO_X Emissions from Fossil-Fired Electric Generating Units Greater than 25 MW in Covered States in 2012 and 2014 in Base Case and with Transport Rule (tons)

	Base Case		Transport Rule	
	2012	2014	2012	2014
Alabama	34,074	31,365	31,607	29,532
Arkansas	15,037	16,644	15,087	16,728
Florida	41,646	45,993	27,645	29,435
Georgia	29,106	19,293	26,660	17,838
Illinois	21,371	22,043	21,102	21,210
Indiana	46,877	46,086	46,789	46,564
Iowa	18,307	19,440	15,746	16,346
Kansas	16,126	13,967	13,425	10,217
Kentucky	37,588	35,296	34,969	31,547
Louisiana	13,433	13,924	13,669	13,943
Maryland	7,179	7,540	6,705	7,248
Michigan	25,989	28,037	25,476	24,248
Mississippi	10,161	11,212	10,639	10,960
Missouri	23,156	23,759	21,788	20,805
New Jersey	3,440	3,668	3,403	3,518
New York	8,336	9,031	8,404	8,399
North Carolina	22,902	20,169	21,081	18,154
Ohio	42,274	41,327	34,576	35,769
Oklahoma	31,415	31,723	20,910	21,200
Pennsylvania	52,895	54,217	50,384	50,446
South Carolina	15,145	16,586	13,810	15,058
Tennessee	15,505	12,141	14,305	8,461
Texas	64,711	65,492	62,824	63,749
Virginia	15,148	15,339	14,311	14,744
West Virginia	26,464	27,099	23,352	22,406
Wisconsin	15,876	16,048	12,840	12,768
Total	654,161	647,439	591,508	571,293

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B. The Impacts on $PM_{2.5}$ and Ozone of the Final SO_2 and NO_X Strategy

The air quality modeling platform described in section V was used by EPA to model the impacts of the final rule SO_2 and NO_X emission reductions on annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone concentrations. In brief, we ran the CAMx model for the meteorological conditions in the year of 2005 for the eastern U.S. modeling domain.[91] Modeling was performed for the 2014 base case and the 2014 air quality-assured trading (*i.e.,* remedy) scenario to assess the expected effects of the final rule on projected $PM_{2.5}$ and ozone design value concentrations and nonattainment and maintenance. The procedures used to project future design values and nonattainment and maintenance are described in section V.

The projected 2014 concentrations of annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone at each monitoring site in the East for which projections were made are provided in the Air Quality Modeling Final Rule TSD. The number of nonattainment and/or maintenance sites in the East for the 2012 base case, 2014 base case, and 2014 remedy for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone are provided in Table VIII.B–1.[92] The average and peak reductions in annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone predicted at 2012 nonattainment and/or maintenance sites due the emission reductions between 2012 and the 2014 remedy are provided in Table VIII.B–2.

[91] As described in the Air Quality Modeling Final Rule TSD, the eastern U.S. was modeled at a horizontal resolution of 12 x 12 km. The remainder of the U.S. was modeled at a resolution of 36 x 36 km.

[92] To provide a point of reference, Table VIII.B–1 also includes the number of nonattainment and/maintenance sites based on ambient design values for the period 2003 through 2007.

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TABLE VIII.B–1—PROJECTED REDUCTION IN NONATTAINMENT AND/OR MAINTENANCE PROBLEMS FOR $PM_{2.5}$ AND OZONE IN THE EASTERN U.S.

	Ambient (2003–2007)	2012 Base case	2014 Base case	2014 remedy	Percent reduction: 2012 base case vs. 2014 remedy (percent)	Percent reduction: 2014 base case vs. 2014 remedy
Annual $PM_{2.5}$ Nonattainment Sites [93]	103	12	7	0	100	100 percent.
Annual $PM_{2.5}$ Maintenance-Only Sites	22	4	3	0	100	100 percent.
24-hour $PM_{2.5}$ Nonattainment Sites	151	20	10	1	95	90 percent.
24-hour $PM_{2.5}$ Maintenance-Only Sites	48	21	12	4	81	67 percent.
Ozone Nonattainment Sites	104	7	4	4	43	No Change.
Ozone Maintenance-Only Sites	65	9	6	6	33	No Change.

TABLE VIII.B–2—AVERAGE AND PEAK REDUCTION IN ANNUAL $PM_{2.5}$, 24-HOUR $PM_{2.5}$, AND OZONE FOR SITES THAT ARE PROJECTED TO HAVE NONATTAINMENT AND/OR MAINTENANCE PROBLEMS IN THE 2012 BASE CASE

	Average reduction: 2012 base Case to 2014 remedy	Peak reduction: 2012 base case to 2014 remedy
Annual $PM_{2.5}$ Nonattainment Sites	2.73 μg/m^3	3.32 μg/m^3.
Annual $PM_{2.5}$ Maintenance-Only Sites	2.99 μg/m^3	3.26 μg/m^3.
24-hour $PM_{2.5}$ Nonattainment Sites	6.8 μg/m^3	11.7 μg/m^3.
24-hour $PM_{2.5}$ Maintenance-Only Sites	6.5 μg/m^3	11.0 μg/m^3.
Ozone Nonattainment Sites	1.9 ppb	2.3 ppb.
Ozone Maintenance-Only Sites	1.8 ppb	2.1 ppb.

The information in Table VIII.B–1 shows that there will be significant reductions in the extent of nonattainment and maintenance problems for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone between 2012 and 2014 as a result of the emission budgets in this rule coupled with emission reductions during this time period from other existing control programs. Specifically, the results of the air quality modeling indicate that no sites are projected to be in nonattainment or projected to have a maintenance problem for annual $PM_{2.5}$ in 2014 with the emission reductions expected from the Transport Rule. As indicated in Table VIII.B–2, the average reduction in annual $PM_{2.5}$ across the twelve 2012 nonattainment sites is 2.73 μg/m^3 and the peak reduction at an individual nonattainment site is 3.32 μg/m^3. Large reductions are also projected at annual $PM_{2.5}$ maintenance-only sites.

For 24-hour $PM_{2.5}$, we project that the number of nonattainment sites will be reduced by 95 percent and the number of maintenance-only sites by 81 percent in 2014 compared to the 2012 base case. The average reduction in 24-hour $PM_{2.5}$ across the twenty 2012 nonattainment sites is 6.8 μg/m^3 and the peak reduction at an individual nonattainment site is 11.7 μg/m^3. Similarly large reductions are projected at 24-hour $PM_{2.5}$ maintenance-only sites, as indicated in Table VIII.B–2.

The emission reductions in the Transport Rule will result in considerable progress toward attainment and maintenance at the 5 sites that remain as nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ standard. On average for these 5 sites, the predicted amount of $PM_{2.5}$ reduction in 2014 is 64 percent of what is needed for these sites to attain and/or maintain the 24-hour standard.

Thus, the SO_2 and NO_X emission reductions which will result from the Transport Rule will greatly reduce the extent of $PM_{2.5}$ nonattainment and maintenance problems by 2014 and beyond. As described previously, these emission reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment and/or maintenance sites in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in residual nonattainment sites. The emission reductions will also help those locations that may have maintenance problems.

Based on the 2012 base air quality modeling for ozone, 16 sites in the East are projected to be nonattainment or have problems maintaining the 1997 ozone standard. The summer NO_X reductions are projected to lower 8-hour ozone concentration by 1.8 ppb, on average by 2014, at monitoring sites projected to be nonattainment and/or have maintenance problems in the 2012 base case. We expect that the number of nonattainment sites will be reduced by 43 percent and the number of maintenance-only sites by 33 percent in 2014 compared to the 2012 base case. Thus, our modeling indicates that by 2014 the summer NO_X emission reductions in this rule, coupled with other existing control programs, will lower ozone concentrations in the East and help bring areas closer to attainment for the 8-hour ozone NAAQS. As discussed in section III of this preamble, EPA plans to finalize its reconsideration of the 2008 revised ozone NAAQS soon, and these reductions will help areas achieve those revised NAAQS.

C. Benefits

1. Human Health Benefit Analysis

To estimate the human health benefits of the final Transport Rule, EPA used the BenMAP model to quantify the changes in $PM_{2.5}$ and ozone-related health impacts and monetized benefits based on changes in air quality. For context, it is important to note that the magnitude of the $PM_{2.5}$ benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$

[93] "Nonattainment" is used to denote sites that are projected to have both nonattainment and maintenance problems.

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concentrations and premature mortality. For this rule we cite two key empirical studies, one based on the American Cancer Society cohort study [94] and the other based on the extended Six Cities cohort study.[95]

The estimated benefits of this rule are substantial, particularly when viewed within the context of the total public health burden of $PM_{2.5}$ and ozone air pollution. A recent EPA analysis estimated that 2005 levels of $PM_{2.5}$ and ozone were responsible for between 130,000 and 320,000 $PM_{2.5}$-related and 4,700 ozone-related premature deaths, or about 6.1 percent of total deaths from all causes in the continental U.S. (using the lower end of the range for premature deaths).[96] In other words, 1 in 20 deaths in the U.S. is attributable to $PM_{2.5}$ and ozone exposure. This same analysis attributed almost 200,000 non-fatal heart attacks, 90,000 hospital admissions due to respiratory or cardiovascular illness, 2.5 million cases of aggravated asthma among children, and many other human health impacts to exposure to these two air pollutants.

We estimate that $PM_{2.5}$ improvements under the Transport Rule will, starting in 2014, annually reduce between 13,000 and 34,000 $PM_{2.5}$-related premature deaths, 15,000 non-fatal heart attacks, 8,700 incidences of chronic bronchitis, 8,500 hospital admissions, and 400,000 cases of aggravated asthma while also reducing 10 million days of restricted activity due to respiratory illness and approximately 1.7 million work-loss days. We also estimate substantial health improvements for children from fewer cases of upper and lower respiratory illness and acute bronchitis.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include between 27 and 120 fewer premature mortalities, 240 fewer hospital admissions for respiratory illnesses, 86 fewer emergency room admissions for asthma, 160,000 fewer days with restricted activity levels, and 51,000 fewer days where children are absent from school due to illnesses.

Table VIII.C–1 presents the primary estimates of annual reduced incidence of $PM_{2.5}$ and ozone-related health effects for the final rule based on 2014 air quality improvements. When adding the PM and ozone-related mortalities together, we find that the Transport Rule will yield between 13,000 and 34,000 fewer premature mortalities annually. By 2014, in combination with other federal and state air quality actions, the Transport Rule will address a substantial fraction of the total public health burden of $PM_{2.5}$ and ozone air pollution.

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VIII.C-1 Estimated Annual Reductions in Incidences of Health Effects Based on 2014 Modeling[a]

Health Effect	Within transport region	Beyond transport region	Total
PM-Related endpoints			
Premature Mortality			
Pope et al. (2002) (age >30)	13,000 (5,200—21,000)	33 (5—60)	13,000 (5,200—21,000)
Laden et al. (2006) (age >25)	34,000 (18,000—49,000)	84 (31—140)	34,000 (18,000—49,000)
Infant (< 1 year)	59 (-47—160)	0.15 (-0.2—0.5)	59 (-47—160)
Chronic Bronchitis	8,700 (1,600—16,000)	23 (-5—50)	8,700 (1,600—16,000)
Non-fatal heart attacks (age > 18)	15,000 (5,600—24,000)	40 (7—72)	15,000 (5,600—24,000)
Hospital admissions—respiratory (all ages)	2,700 (1,300—4,000)	5 (2—9)	2,700 (1,300—4,000)
Hospital admissions—cardiovascular (age > 18)	5,700 (4,200—6,600)	15 (10—19)	5,800 (4,200—6,600)
Emergency room visits for asthma (age < 18)	9,800 (5,800—14,000)	21 (7—36)	9,800 (5,800—14,000)
Acute bronchitis (age 8-12)	19,000 (-630—37,000)	50 (-29—130)	19,000 (-660—37,000)
Lower respiratory symptoms (age 7-14)	240,000 (120,000—360,000)	630 (130—1,100)	240,000 (120,000—360,000)
Upper respiratory symptoms (asthmatics age 9-18)	180,000 (57,000—310,000)	480 (-25—980)	180,000 (57,000—310,000)
Asthma exacerbation (asthmatics 6-18)	400,000 (45,000—1,100,000)	1,100 (-250—2,900)	400,000 (45,000—1,100,000)
Lost work days (ages 18-65)	1,700,000 (1,500,000—1,900,000)	4,300 (3,500—5,200)	1,700,000 (1,500,000—1,900,000)
Minor restricted-activity days (ages 18-65)	10,000,000 (8,400,000—11,000,000)	26,000 (20,000—32,000)	10,000,000 (8,400,000—12,000,000)

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Ozone-related endpoints				
Premature mortality				
Multi-city and NMMAPS	Bell et al. (2004) (all ages)	27 (11—42)	0.1 (0.01—0.3)	27 (11—42)
	Schwartz et al. (2005) (all ages)	41 (17—64)	0.2 (0.1—0.4)	41 (17—65)
	Huang et al. (2005) (all ages)	37 (17—57)	0.2 (0.1—0.4)	37 (17—57)
Meta-analyses	Ito et al. (2005) (all ages)	120 (78—160)	0.6 (0.3—0.9)	120 (79—160)
	Bell et al. (2005) (all ages)	87 (48—130)	0.5 (0.2—0.8)	87 (48—130)
	Levy et al. (2005) (all ages)	120 (89—150)	0.7 (0.4—0.9)	120 (90—160)
Hospital admissions—respiratory causes (ages > 65)		160 (21—280)	1.2 (0.1—2.3)	160 (21—290)
Hospital admissions—respiratory causes (ages <2)		83 (43—120)	0.5 (0.2—0.8)	84 (43—120)
Emergency room visits for asthma (all ages)		86 (-2—260)	0.4 (-0.2—1.4)	86 (-2—260)
Minor restricted-activity days (ages 18-65)		160,000 (80,000—240,000)	910 (240—1,600)	160,000 (80,000—240,000)
School absence days		51,000 (22,000—73,000)	290 (59—490)	51,000 (22,000—74,000)

[a] Values rounded to two significant figures. Benefits from reducing other criteria pollutants and hazardous air pollutants and ecosystem effects are not included here.
Source: EPA, 2011

2. Quantified and Monetized Visibility Benefits

Only a subset of the expected visibility benefits—those for Class I areas—are included in the monetary benefit estimates we project for this rule. We anticipate improvement in visibility in residential areas where people live, work, and recreate within the Transport Rule region for which we are currently unable to monetize benefits. For the Class I areas we estimate annual benefits of $4.1 billion beginning in 2014 for visibility improvements. The value of visibility benefits in areas where we are unable to monetize benefits could be substantial.

3. Benefits of Reducing GHG Emissions

When fully implemented in 2014, the Transport Rule will reduce emissions of CO_2 from electrical generating units by about 25 million metric tons annually. Using a ‘‘social cost of carbon’’ (SCC) estimate that accounts for the marginal dollar value (*i.e.,* cost) of climate-related damages resulting from CO_2 emissions, previous analyses, including the RIA for the Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Efficiency Standards, have found the total benefit of CO_2 reductions is substantial. The monetary value of these avoided damages also grows over time. Readers interested in learning more about the calculation of the SCC metric should refer to the SCC TSD, Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 [Docket No. EPA–HQ–OAR–2009–0472].

4. Total Monetized Benefits

Table VIII.C–2 presents the estimated annual monetary value of reductions in the incidence of health and welfare effects. These estimates account for increases in the value of risk reduction over time. Total monetized benefits are driven primarily by the reduction in premature fatalities each year, which account for between 89 and 96 percent of total benefits.

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VIII.C-2 Estimated Annual Monetary Value of Reductions in Incidence of Health and Welfare Effects Based on 2014 Modeling (Billions of 2007$)[A]

Health Effect	*Pollutant*	*Within Transport Rule Region*	*Beyond Transport Rule Region[B]*	*Total*
Premature Mortality (Pope et al. 2002 PM mortality and Bell et al. 2004 ozone mortality estimates)				
3% discount rate	$PM_{2.5}$ & O_3	$100 ($8.3—$320)	$0.3 ($0.01—$0.9)	$100 ($8.3—$320)
7% discount rate	$PM_{2.5}$ & O_3	$94 ($7.5—$280)	$0.2 ($0.01—$0.8)	$94 ($7.5—$290)
Premature Mortality (Laden et al. 2006 PM mortality and Levy et al. 2005 ozone mortality estimates)				
3% discount rate	$PM_{2.5}$ & O_3	$270 ($23—$770)	$0.7 ($0.05—$2)	$270 ($23—$770)
7% discount rate	$PM_{2.5}$ & O_3	$240 ($21—$700)	$0.6 ($0.05—$1.8)	$240 ($21—$700)
Chronic Bronchitis	$PM_{2.5}$	$4.2 ($0.2—$19)	$0.01 ($-0.003—$0.06)	$4.2 ($0.2—$19)
Non-fatal heart attacks				
3% discount rate	$PM_{2.5}$	$1.7 ($0.3—$4.2)	$0.004 ($0.003—$0.01)	$1.7 ($0.3—$4.2)
7% discount rate	$PM_{2.5}$	$1.3 ($0.3—$3.1)	$0.004 ($0.002—$0.001)	$1.3 ($0.3—$3.1)
Hospital admissions—respiratory	$PM_{2.5}$ & O_3	$0.04 ($0.02—$0.06)	---	$0.04 ($0.02—$0.06)
Hospital admissions—cardiovascular	$PM_{2.5}$	$0.09 ($0.01—$0.2)	---	$0.09 ($0.01—$0.2)
Emergency room visits for asthma	$PM_{2.5}$ & O_3	$0.003 ($0.002—$0.006)	---	$0.003 ($0.002—$0.006)
Acute bronchitis	$PM_{2.5}$	$0.008 (<$-0.01—$0.02)[c]	---	$0.008 (<$-0.01—$0.02)[c]
Lower respiratory symptoms	$PM_{2.5}$	$0.004 ($0.002—$0.009)	---	$0.004 ($0.002—$0.009)
Upper respiratory symptoms	$PM_{2.5}$	$0.005 (<$0.01—$0.014)	---	$0.005 (<$0.01—$0.014)
Asthma exacerbation	$PM_{2.5}$	$0.02 ($0.002—$0.08)	---	$0.02 ($0.002—$0.08)
Lost work days	$PM_{2.5}$	$0.2 ($0.17—$0.24)	---	$0.2 ($0.17—$0.24)
School loss days	O_3	$0.01	---	$0.01

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		($0.004–$0.013)		($0.004–$0.013)
Minor restricted-activity days	$PM_{2.5}$ & O_3	$0.7 ($0.3–$1)	---	$0.7 ($0.3–$1)
Recreational visibility, Class I areas	$PM_{2.5}$			$4.1
Social cost of carbon (3% discount rate, 2014 value)	CO_2			$0.6
Monetized total Benefits (Pope et al. 2002 $PM_{2.5}$ mortality and Bell et al. 2004 ozone mortality estimates)				
3% discount rate	$PM_{2.5}$, O_3	$110 ($8.8–$340)	$0.28 ($0.01–$0.9)	$120 ($14–$350)
7% discount rate	$PM_{2.5}$, O_3	$100 ($8–$310)	$0.25 ($0.01–$0.85)	$110 ($13–$320)
Monetized total Benefits (Laden et al. 2006 $PM_{2.5}$ mortality and Levy et al. 2005 ozone mortality estimates)				
3% discount rate	$PM_{2.5}$, O_3	$270 ($24–$800)	$0.7 ($0.05–$2.1)	$280 ($29–$810)
7% discount rate	$PM_{2.5}$, O_3	$250 ($22–$720)	$0.6 ($0.04–$1.9)	$250 ($26–$730)

[A] Values rounded to two significant figures. Benefits from reducing other criteria pollutants and hazardous air pollutants and ecosystem effects are not included here.

[B] Monetary value of endpoints marked with dashes are < $100,000.

[C] The negative estimates for certain endpoints are the result of the weak statistical power of the study used to calculate these health impacts and do not suggest that increases in air pollution exposure result in decreased health impacts.

Source: EPA, 2011

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5. How do the benefits in 2012 compare to 2014?

The magnitude of SO_2 emission reductions achieved under the rule is actually larger in 2012 than in 2014, due to substantial emission reductions expected to occur in the baseline (*i.e.,* unrelated to the Transport Rule) between those years. As a consequence, EPA expects correspondingly greater reductions in harmful effects to accrue in 2012 compared to 2014.

As presented in Table VIII.C–1, the Transport Rule is expected to prevent between 13,000 and 34,000 premature deaths annually from 2014 onward due to reductions in ambient $PM_{2.5}$ concentrations, which are most significantly impacted by SO_2 emission reductions. Based on EPA's analysis of power sector emission reductions under the Transport Rule, the decline in SO_2 in 2012 is 4 percent greater than the decline in SO_2 in 2014 in the states modeled. EPA therefore anticipates that the Transport Rule will deliver greater reductions in ambient $PM_{2.5}$ concentrations in 2012 and increased annual benefits to human health and welfare beyond those presented in this section.

6. How do the benefits compare to the costs of this final rule?

The estimated annual private costs to implement the emission reduction requirements of the final rule for the Transport Rule states are $1.85 billion in 2012 and $0.83 billion in 2014 (2007 $). These costs are the annual incremental electric generation production costs that are expected to occur with the Transport Rule. The EPA uses these costs as compliance cost estimates in developing cost-effectiveness estimates.

In estimating the net benefits of regulation, the appropriate cost measure is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $0.81 billion in 2014 assuming either a 3 percent discount rate or a 7 percent discount rate. Thus, the annual net benefit (social benefits minus social costs) as shown in Table VIII.C–3 for the Transport Rule is approximately $120 to $280 billion or

$110 to $250 billion (3 percent and 7 percent discount rates, respectively) in 2014. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

A listing of the benefit categories that could not be quantified or monetized in our benefit estimates is provided in Table VIII.C–4.

TABLE VIII.C–3—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL TRANSPORT RULE IN 2014
[Billions of 2007$] [a]

Description	Transport Rule remedy (billions of 2007 $)	
	3% discount rate	7% discount rate
Social costs	$0.81	$0.81.
Total monetized benefits [b]	$120 to $280	$110 to $250.
Net benefits (benefits-costs)	$120 to $280	$110 to $250.

[a] All estimates are for 2014, and are rounded to two significant figures.
[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ and ozone and the welfare benefits associated with improved visibility in Class I areas. The reduction in premature mortalities account for over 90 percent of total monetized $PM_{2.5}$ and ozone benefits.

The annualized regional cost of the rule, as quantified here, is EPA's best assessment of the cost of implementing the Transport Rule. These costs are generated from rigorous economic modeling of changes in the power sector expected from the rule. This type of analysis, using IPM, has undergone peer review and been upheld in federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the Transport Rule to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to be about $26 million (see section XII.B, Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to this rule, such as the costs associated with the retirement of smaller or less efficient EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with Title V that new program entrants face.

An optimization model was employed that assumes cost minimization. Costs may be understated if the regulated community chooses not to minimize its compliance costs in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared with the quantified costs of the program to the power sector. However, EPA's experience and results of independent evaluation suggests that costs are likely to be lower by some degree (see RIA for details). The annualized cost estimates presented are the best and most accurate based upon available information. In a separate analysis, EPA estimates the indirect costs and impacts of higher electricity prices on the entire economy. These impacts are summarized in the RIA for this final rule.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. While uncertainties in the underlying scientific and economics literatures (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA's inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emission inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations, including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions. This approach calculates a mean value across value of a statistical life (VSL) estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[97] The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, which are discussed throughout the RIA document.

As Table VIII.C–2 indicates, total annual monetary benefits are driven primarily by the reduction in premature mortalities each year. Some key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) EPA assumes inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a 24-hour basis. Plausible biological mechanisms for this effect have been hypothesized for the endpoints included in the primary analysis, and the weight of the available epidemiological evidence supports an assumption of causality.

[97] In this analysis, we adjust the VSL to account for a different currency year (2007$) and to account for income growth to 2014. After applying these adjustments to the $6.3 million value, the VSL is $8.7 million.

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(2) EPA assumes all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because the proportion of certain components in the PM mixture produced via precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with the fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.

The EPA recognizes the difficulties, assumptions, and inherent uncertainties in the overall enterprise. The analyses upon which the Transport Rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

There are a number of health and environmental effects that we were unable to quantify or monetize. A complete benefit-cost analysis of the Transport Rule requires consideration of all benefits and costs expected to result from the rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that were not quantified or monetized in our estimate are provided in Table VIII.C–4.

TABLE VIII.C–4—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE TRANSPORT RULE

Pollutant/Effect	Endpoint
PM: Health [a]	Low birth weight.
	Pulmonary function.
	Chronic respiratory diseases other than chronic bronchitis.
	Non-asthma respiratory emergency room visits.
	UVb exposure [b].
PM: Welfare	Household soiling.
	Visibility in residential areas.
	Visibility in non-class I areas and class 1 areas in NW, NE, and Central regions.
	UVb exposure [b].
	Global climate impacts [b].
Ozone: Health	Chronic respiratory damage.
	Premature aging of the lungs.
	Non-asthma respiratory emergency room visits.
	UVb exposure [b].
Ozone: Welfare	Yields for:
	—Commercial forests.
	—Fruits and vegetables, and
	—Other commercial and noncommercial crops.
	Damage to urban ornamental plants.
	Recreational demand from damaged forest aesthetics.
	Ecosystem functions.
	Increased exposure to UVb [b].
	Climate impacts.
NO_2: Health	Respiratory hospital admissions.
	Respiratory emergency department visits.
	Asthma exacerbation.
	Acute respiratory symptoms.
	Premature mortality.
	Pulmonary function.
NO_2: Welfare	Commercial fishing and forestry from acidic deposition effects.
	Commercial fishing, agriculture and forestry from nutrient deposition effects.
	Recreation in terrestrial and estuarine ecosystems from nutrient deposition effects.
	Other ecosystem services and existence values for currently healthy ecosystems.
	Coastal eutrophication from nitrogen deposition effects.
SO_2: Health	Respiratory hospital admissions.
	Asthma emergency room visits.
	Asthma exacerbation.
	Acute respiratory symptoms.
	Premature mortality.
	Pulmonary function.
SO_2: Welfare	Commercial fishing and forestry from acidic deposition effects.
	Recreation in terrestrial and aquatic ecosystems from acid deposition effects.
	Increased mercury methylation.
Mercury: Health	Incidence of neurological disorders.
	Incidence of learning disabilities.
	Incidences in developmental delays.
Mercury: Welfare	Impact on birds and mammals (*e.g.*, reproductive effects).
	Impacts to commercial, subsistence and recreational fishing.

Source: EPA.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] May result in benefits or disbenefits.

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7. What are the unquantified and non-monetized benefits of the Transport Rule emission reductions?

Important benefits beyond the human health and welfare benefits quantified in this section and the RIA are expected to occur from this rule. These other benefits occur directly from NO_X and SO_2 emission reductions and from co-benefits due to Transport Rule compliance. These benefits are listed in Table VIII.C–4. Some of the more important examples include: Reduced acidification and, in the case of NO_X, eutrophication of water bodies; possible reduced nitrate contamination of drinking water; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as, soiling and other materials damage. To illustrate the important nature of benefit categories EPA is currently unable to monetize, we discuss four categories of public welfare and environmental impacts related to reductions in emissions required by the Transport Rule: Reduced acid deposition, reduced eutrophication of estuaries, reduced mercury methylation and deposition, and reduced vegetation impairment from ozone.

a. What are the benefits of reduced deposition of sulfur and nitrogen to aquatic, forest, and coastal ecosystems?

Atmospheric deposition of sulfur and nitrogen, often referred to as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, across state borders. These compounds are deposited onto terrestrial and aquatic ecosystems across the U.S., contributing to the problems of acidification.

(1) Acid Deposition and Acidification of Lakes and Streams

The extent of adverse effects of acid deposition on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. The neutralizing ability depends largely on the watershed's physical characteristics, such as geology, soils, and size. A key indicator of neutralizing ability is termed Acid Neutralizing Capacity (ANC). Higher ANC indicates greater ability to neutralize acidity. Acidic conditions occur more frequently during rainfall and snowmelt that cause high flows of water, and less commonly during low-flow conditions except where chronic acidity conditions are severe. Biological effects are primarily attributable to a combination of low pH and high inorganic aluminum concentrations. Biological effects of episodes include reduced fish condition factor—changes in species composition and declines in aquatic species richness across multiple taxa, ecosystems and regions—as well as fish mortality. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly, the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and southeastern streams. This regulatory action will decrease acid deposition within and downwind of the transport region and is likely to have positive effects on the health and productivity of aquatic ecosystems in the region.

(2) Acid Deposition and Forest Ecosystem Impacts

Acidifying deposition has altered major biogeochemical processes in the U.S. by increasing the nitrogen and sulfur content of soils, accelerating nitrate and sulfate leaching from soil to drainage waters, depleting base cations (especially calcium and magnesium) from soils, and increasing the mobility of aluminum. Inorganic aluminum is toxic to some tree roots. Plants affected by high levels of aluminum from the soil often have reduced root growth, which restricts the ability of the plant to take up water and nutrients, especially calcium.[98] These direct effects can, in turn, influence the response of these plants to climatic stresses such as droughts and cold temperatures. They can also influence the sensitivity of plants to other stresses, including insect pests and disease,[99] leading to increased mortality of canopy trees.

Both coniferous and deciduous forests throughout the eastern U.S. are experiencing gradual losses of base cation nutrients from the soil due to accelerated leaching from acidifying deposition. This change in nutrient availability may reduce the quality of forest nutrition over the long term. Evidence suggests that red spruce and sugar maple in some areas in the eastern U.S. have experienced declining health because of this deposition. For red spruce *(Picea rubens)*, dieback or decline has been observed across high elevation landscapes of the northeastern U.S. and, to a lesser extent, the southeastern U.S. Acidifying deposition has been implicated as a causal factor.[100]

This regulatory action will decrease acid deposition within and downwind of the transport region and is likely to have positive effects on the health and productivity of forest systems in the region.

b. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources.

Atmospheric deposition of nitrogen is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. A recent assessment of 141 estuaries nationwide by the National Oceanic and Atmospheric Administration (NOAA) concluded that 19 estuaries (13 percent) suffered from moderately high or high levels of eutrophication due to excessive inputs of both nitrogen and phosphorus, and a majority of these estuaries are located in the coastal area from North Carolina to Massachusetts.[101] For estuaries in the Mid-Atlantic region, the contribution of atmospheric distribution to total nitrogen loads is estimated to range between 10 percent and 58 percent.[102]

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[102] Valigura, R.A., R.B. Alexander, M.S. Castro, T.P. Meyers, H.W. Paerl, P.E. Stacy, and R.E. Turner. 2001. Nitrogen Loading in Coastal Water

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Eutrophication in estuaries is associated with a range of adverse ecological effects. The conceptual framework developed by NOAA emphasizes four main types of eutrophication effects: low dissolved oxygen (DO), harmful algal blooms (HABs), loss of submerged aquatic vegetation (SAV), and low water clarity. Low DO disrupts aquatic habitats, causing stress to fish and shellfish, which, in the short-term, can lead to episodic fish kills and, in the long-term, can damage overall growth in fish and shellfish populations. Low DO also degrades the aesthetic qualities of surface water. In addition to often being toxic to fish and shellfish, and leading to fish kills and aesthetic impairments of estuaries, HABs can, in some instances, also be harmful to human health. SAV provides critical habitat for many aquatic species in estuaries and, in some instances, can also protect shorelines by reducing wave strength. Therefore, declines in SAV due to nutrient enrichment are an important source of concern. Low water clarity is the result of accumulations of both algae and sediments in estuarine waters. In addition to contributing to declines in SAV, high levels of turbidity also degrade the aesthetic qualities of the estuarine environment.

Estuaries in the eastern United States are an important source of food production, in particular fish and shellfish production. The estuaries are capable of supporting large stocks of resident commercial species, and they serve as the breeding grounds and interim habitat for several migratory species.

This rule is anticipated to reduce nitrogen deposition within and downwind of the Transport Rule states. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region.

c. Mercury Methylation and Deposition

Mercury is a highly neurotoxic contaminant that enters the food web as a methylated compound, methylmercury.[103] The contaminant is concentrated in higher trophic levels, including fish eaten by humans. Experimental evidence has established that only inconsequential amounts of methylmercury can be produced in the absence of sulfate. Current evidence indicates that in watersheds where mercury is present, increased SO_X deposition very likely results in methylmercury accumulation in fish.[104] [105] The SO_2 Integrated Science Assessment concluded that evidence is sufficient to infer a causal relationship between sulfur deposition and increased mercury methylation in wetlands and aquatic environments.

d. Ozone Vegetation Effects

Ozone causes discernible injury to a wide array of vegetation.[106] In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts.[107] Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function.[108] [109]

Assessing the impact of ground-level ozone on forests in the eastern United States involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as ''biomass loss.'' Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, and the decreases predicted using the seedlings should be related to the decrease in overall plant fitness for mature trees, but the magnitude of the effect may be higher or lower depending on the tree species.[110] In areas where certain ozone-sensitive species dominate the forest community, the biomass loss from ozone can be significant. Significant biomass loss can be defined as a more than 2 percent annual biomass loss, which would cause long-term ecological harm, as the short-term negative effects on seedlings compound to affect long-term forest health.[111]

Urban ornamentals are an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. Because ozone causes visible foliar injury, the aesthetic value of ornamentals (such as petunia, geranium, and poinsettia) in urban landscapes would be reduced. Sensitive ornamental species would require more frequent replacement and/or increased maintenance (fertilizer or pesticide application) to maintain the desired appearance because of exposure to ambient ozone.[112] In addition, many businesses rely on healthy-looking vegetation for their livelihoods (*e.g.,* horticulturalists, landscapers, Christmas tree growers, farmers of leafy crops, etc.) and a variety of ornamental species have been listed as sensitive to ozone.[113]

D. Costs and Employment Impacts

1. Transport Rule Costs and Employment Impacts

For the affected region, the projected annual private incremental costs of the rule to the power industry are $1.4 billion in 2012 and $0.8 billion in 2014. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions to meet the requirements set forth in the rule. Estimates are in 2007 dollars.

In estimating the net benefits of regulation, the appropriate cost measure

Bodies: An Atmospheric Perspective. Washington, DC: American Geophysical Union.

[103] U.S. Environmental Protection Agency (U.S. EPA). 2008. Integrated Science Assessment for Sulfur Oxides—Health Criteria (Final Report). National Center for Environmental Assessment, Research Triangle Park, NC. September. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=198843.*

[104] Drevnick, P.E., D.E. Canfield, P.R. Gorski, A.L.C. Shinneman, D.R. Engstrom, D.C.G. Muir, G.R. Smith, P.J. Garrison, L.B. Cleckner, J.P. Hurley, R.B. Noble, R.R. Otter, and J.T. Oris. 2007. Deposition and cycling of sulfur controls mercury accumulation in Isle Royale fish. Environmental Science and Technology 41(21):7266–7272.

[105] Munthe, J., R.A. Bodaly, B.A. Branfireun, C.T. Driscoll, C.C. Gilmour, R. Harris, M. Horvat, M. Lucotte, and O. Malm. 2007. Recovery of mercury-contaminated fisheries. AMBIO:A Journal of the Human Environment 36:33–44.

[106] Fox, S., Mickler, R.A. (Eds.). 1996. Impact of Air Pollutants on Southern Pine Forests. Ecological Studies. (Vol. 118, 513 pp.) New York: Springer-Verlag.

[107] U.S. Environmental Protection Agency (U.S. EPA). 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February. *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

[108] De Steiguer, J., Pye, J., Love, C. 1990. Air Pollution Damage to U.S. Forests. Journal of Forestry, 88(8), 17–22.

[109] Pye, J.M. 1988. Impact of ozone on the growth and yield of trees: A review. Journal of Environmental Quality, 17, 347–360.

[110] Chappelka, A.H., Samuelson, L.J. 1998. Ambient ozone effects on forest trees of the eastern United States: a review. New Phytologist, 139, 91–108.

[111] Heck, W.W. & Cowling, E.B. 1997. The need for a long term cumulative secondary ozone standard—an ecological perspective. Environmental Management, January, 23–33.

[112] U.S. Environmental Protection Agency (U.S. EPA). 2007. Review of the National Ambient Air Quality Standards for Ozone: Policy assessment of scientific and technical information. Staff paper. Office of Air Quality Planning and Standards. EPA–452/R–07–007a. July. *http://www.epa.gov/ttn/naaqs/standards/ozone/data/2007_07_ozone_staff_paper.pdf.*

[113] Abt Associates, Inc. 2005. U.S. EPA. Urban ornamental plants: sensitivity to ozone and potential economic losses. Memorandum to Bryan Hubbell and Zachary Pekar.

is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $0.8 billion annually in 2014. Overall, the economic impacts of the Transport Rule are modest in 2014, particularly in light of the large benefits ($120 to $280 billion annually at a 3 percent discount rate and $110 to $250 billion annually at a 7 percent discount rate) we expect, as shown in section XII.A of this preamble. Ultimately, we believe the electric power industry will pass along most of the costs of the rule to consumers, so that the costs of the rule will largely fall upon the consumers of electricity. For more information on electricity price changes that result from this final rule, refer to section XII.H (Statement of Energy Effects) later in this preamble.

For this rule, EPA analyzed the costs using the Integrated Planning Model (IPM). The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for SO_2 and NO_X throughout the contiguous United States for the entire power system. Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html*.

EPA also included an analysis of impacts of the final rule to industries outside of the electric power sector by using the Multi-Market Model. This model is a partial equilibrium economic impact model that includes 100 sectors that cover energy, manufacturing, and service applications and is designed to capture the short-run effects associated with an environmental regulation. This model was used to estimate economic impacts for the proposed MATS, and the promulgated industrial boilers major and area source standards and CISWI standard.

We use the Multi-Market Model to estimate the social costs of the final rule. Using this model, we estimate the social costs of the final rule to be approximately $0.8 billion (2007 dollars), which is close to the compliance costs. Documentation for the Multi-Market Model can be found in the RIA for this final rule.

Also note that as explained in section V.B (Baseline for Pollution Transport Analysis), the baseline used in this analysis assumes no CAIR. As explained in that section, EPA believes that this is the most appropriate baseline to use for purposes of determining whether an upwind state has an impact on a downwind monitoring site in violation of section 110(a)(2)(D).

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Such an analysis is of particular concern in the current economic climate as sustained periods of excess unemployment may introduce a wedge between observed (market) wages and the social cost of labor. In such conditions, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this rule). For that reason, EPA also includes estimates of job impacts associated with the final rule. EPA presents an estimate of short-term employment opportunities as a result of increased demand for pollution control equipment. Overall, the results suggest that the final rule could support a net increase of roughly 2,250 job-years in direct employment in 2014.

The basic approach to estimate these employment impacts involved using projections from IPM from the final rule analysis such as the amount of capacity that will be retrofit with control technologies, for various energy market implications, along with data on labor and resource needs of new pollution controls and labor productivity from secondary sources, to estimate employment impacts for 2014. This analysis was also applied for the proposed MATS. For more information, refer to Appendix D of the RIA for the final Transport Rule.''

EPA relied on Morgenstern, et al. (2002), a study that is a basis for employment impacts estimated for the final industrial boiler major and area source rules and CISWI standard, and the proposed MATS. The Morgenstern study identifies three economic mechanisms by which pollution abatement activities can indirectly influence jobs: (1) Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls (''demand effect''); (2) pollution abatement activities require additional labor services to produce the same level of output (''cost effect''); and (3) post regulation production technologies may be more or less labor intensive (*i.e.*, more/less labor is required per dollar of output) (''factor-shift effect'').

Using plant-level Census information between the years 1979 and 1991, Morgenstern, et al., estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spending on pollution abatement results in a small net increase of 1.6 jobs; however, the estimated effect is not statistically significant. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes. The conclusion is similar to Berman and Bui (2001), who found that increased air quality regulation in Los Angeles did not cause large employment changes. For more information, please refer to the RIA for this final rule.

The ranges of job effects calculated using the Morgenstern, et al., approach are listed in Table VIII.D–1.

TABLE VIII.D–1—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

[Estimates using Morgenstern, et al. (2002)]

	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure [a].	¥3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA Estimate for Final Rule [b]	+ 200 to ¥3,000	+ 400 to 2,000	0 to 2,000	¥1,000 to + 3,000.

[a] Expressed in 1987 dollars. *See* footnote a of Table 8–3 in the RIA for the inflation adjustment factor used in the analysis.

[b] According to the 2007 Economic Census, the electric power generation, transmission, and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

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EPA recognizes there may be other job effects which are not considered in the Morgenstern, et al., study. Although EPA has considered some economy-wide changes in industry output as shown earlier with the Multi-Market model, we do not have sufficient information to quantify other associated job effects associated with this rule.

2. End-Use Energy Efficiency

EPA believes that achievement of energy efficiency (EE) improvements in homes, buildings, and industry is an important component of achieving emission reductions from the power sector while minimizing associated compliance costs. By reducing electricity demand, energy efficiency avoids emissions of all pollutants associated with electricity generation, including emissions of NO_X and SO_2 targeted by this final rule, and reduces the need for investments in EGU emission control technologies in order to meet emission reduction requirements. Moreover, energy efficiency can often be implemented at a lower cost than traditional control technologies.

EPA recognizes that significant opportunities remain for energy efficiency improvements in businesses, homes, and industry. However, there are several informational and market barriers that limit investment in cost-effective energy efficient practices. Several federal programs authorized under the CAA, including ENERGY STAR, are designed to address these barriers.

Congress, EPA, and states have all recognized the value of incorporating energy efficiency into air regulatory programs. Several allowance-based programs—including the Acid Rain Program, EPA's NO_X Budget Trading program, and the Regional Greenhouse Gas Initiative (an effort of 10 states from the Northeast and Mid-Atlantic regions) – have provided mechanisms for rewarding energy efficiency through either the award of allowances, typically through the use of a fixed set-aside pool, or the use of revenues obtained through the auction of allowances. The emission caps established by these programs are unaffected by this approach. However, to the extent electricity demand reductions are realized, compliance costs are reduced. In addition to these allowance-based programs, EPA has also provided guidance [114] concerning the recognition, in SIPs, of emission reduction benefits of energy efficiency and has approved the inclusion of EE measures in individual SIPs.[115]

While all remedy options considered in the proposed rule would have lead to an increase in the relative cost-effectiveness of EE investments by internalizing environmental costs associated with emission of these pollutants, EPA took comment on whether EPA has authority, and whether it would be appropriate for EPA, to consider EE in developing the allowance allocation methodology and to consider other approaches for encouraging EE in the Transport Rule.

Some commenters suggested that EPA has authority to consider EE in developing the allocation methodology. Other commenters do not believe EPA has the authority to consider EE. Some commenters suggested that EPA should establish an EE set-aside provision. Other commenters suggested that EPA should allow, and help, states to establish EE set-asides as states transition from Transport Rule FIPs to SIPs. EPA believes that, while EE set-asides can be effective at encouraging incremental investments in EE, EE set-asides are more likely to be practically and effectively implemented at the state level. Establishing EE set-asides in the allowance allocation provisions in the final rule would not allow for the tailoring of the set-asides to the unique characteristics of individual states and would not build on the existing EE program delivery infrastructure that many states already possess. Instead of establishing EPA-administered EE set-asides in the final rule, EPA is clarifying that it allows and supports EE set-asides (including auction-based approaches) in abbreviated or full SIPs that states may submit, as provided in the final rule. Under this approach states have the ability to implement EE set-asides tailored to their state circumstances, if they choose. EPA anticipates providing additional information in the future for states on EE set-asides, as needed.[116]

As discussed elsewhere in this preamble, the final rule provides for submission and approval of abbreviated and full SIPs providing for continued state participation in the Transport Rule trading programs, and adopting alternative allowance allocation methodologies (which may include EE set-asides) to the allocation methodologies adopted in the FIPs. While the final rule establishes certain requirements for approval of any such alternative allocation methodology, the final rule provides states flexibility to create state-implemented EE set-asides.

IX. Related Programs and the Transport Rule

A. Transition From the Clean Air Interstate Rule

1. Key Differences Between the Transport Rule and CAIR

The Transport Rule replaces CAIR and its associated trading programs. There are a number of differences between implementation of the Transport Rule and implementation of CAIR. This section describes key implementation differences including differences in states covered, compliance deadlines, applicability, structure of the remedy, provisions for early reductions, and provisions for SIPs. The next section discusses the transition from CAIR to the Transport Rule.

States covered. The states covered by the Transport Rule differ somewhat from states covered by CAIR. This section summarizes differences in state coverage. EPA's approach to determine states covered by the Transport Rule is discussed in sections V and VI of this preamble.

The Transport Rule's SO_2 and annual NO_X requirements apply to covered sources in the 23 states listed in Table III–1 in section III of this preamble. CAIR's SO_2 and annual NO_X requirements applied to covered sources in 25 states. There are many states in common between the Transport Rule and CAIR SO_2 and annual NO_X programs. The differences are summarized in Table IX.A–1.

[114] U.S. EPA. 2004. Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures. *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf.*

[115] Metropolitan Washington Council of Governments developed a regional air quality plan for the eight-hour ozone standard for the DC Region nonattainment area that included an EE measure. The plan was adopted by Virginia, Maryland, and the District of Columbia and the respective ozone SIPs were approved by the EPA regions in 2007.

[116] Because the question of EPA authority to create EE set-asides in the FIPs would be best addressed in the context of actual FIP provisions for EPA-created EE set-asides and EPA is, for other reasons, not adopting such provisions in the final rule, EPA is not addressing in the final rule the question of EPA's authority.

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TABLE IX.A–1—DIFFERENCES IN SO_2 AND ANNUAL NO_X STATE COVERAGE BETWEEN THE TRANSPORT RULE AND CAIR

State	Transport rule SO_2 and annual NO_X programs	CAIR SO_2 and annual NO_X programs
Kansas	Yes	No.
Minnesota	Yes	No.
Nebraska	Yes	No.
Delaware	No	Yes.
District of Columbia	No	Yes.
Florida	No	Yes.
Louisiana	No	Yes.
Mississippi	No	Yes.

The Transport Rule's ozone-season NO_X requirements apply to covered sources in the 20 states listed in Table III–1 in section III of this preamble, while CAIR's ozone-season NO_X requirements applied to 26 states. There are many states in common between the Transport Rule and CAIR ozone-season NO_X programs. The differences are summarized in Table IX.A–2.

TABLE IX.A–2—DIFFERENCES IN OZONE-SEASON NO_X STATE COVERAGE BETWEEN THE TRANSPORT RULE AND CAIR

State	Transport rule ozone-season NO_X program	CAIR ozone-season NO_X program
Georgia	Yes	No.
Texas	Yes	No.
Connecticut	No	Yes.
Delaware	No	Yes.
District of Columbia	No	Yes.
Iowa	No	Yes.
Massachusetts	No	Yes.
Michigan	No	Yes.
Missouri	No	Yes.
Wisconsin	No	Yes.

In addition, EPA is proposing a supplemental notice to apply Transport Rule ozone-season requirements to the states of Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin, as discussed in section III of this preamble.

The transition from CAIR to the Transport Rule is discussed in section IX.A.2 and SIPs are discussed in section X of this preamble.

Compliance deadlines. The Transport Rule reduction requirements commence January 1, 2012 for annual NO_X and SO_2 requirements and May 1, 2012 for ozone-season NO_X requirements. More stringent SO_2 reduction requirements commence January 1, 2014 for Group 1 states.

In contrast, the first phase of CAIR NO_X reductions commenced January 1, 2009 for annual NO_X requirements and May 1, 2009 for ozone-season NO_X requirements. On January 1, 2010, the first phase of CAIR SO_2 requirements commenced. However, in anticipation of CAIR, SO_2 reductions actually started as early as 2006 because of the incentive to reduce emissions and bank Title IV Acid Rain Program SO_2 allowances for use when their value would increase under CAIR in 2010 and later. The second phase of CAIR reductions would have (if not replaced by the Transport Rule) commenced January 1, 2015 for annual NO_X and SO_2 requirements, and May 1, 2015 for ozone-season NO_X requirements.

Applicability. Except for the changes to the states covered, the general applicability provisions of the final Transport Rule trading programs are essentially the same as the CAIR general applicability provisions, with a few exceptions.

First, the final Transport Rule does not allow any non-covered units to opt into the trading programs, for the reasons discussed in section VII.B of this preamble. In contrast, under CAIR, through SIPs, the states could elect to allow boilers, combustion turbines, and other combustion devices to opt into the CAIR trading programs under opt-in provisions specified by EPA.

Second, the Transport Rule FIPs' ozone-season NO_X trading program applicability provisions do not cover NO_X SIP Call small EGUs and non-EGUs that a number of CAIR states brought into the CAIR ozone-season NO_X trading program. The Transport Rule does allow any state in the ozone-season NO_X program, through SIPs, to expand the applicability of the Transport Rule ozone-season NO_X trading program to cover small EGUs. However, the Transport Rule does not allow states to expand the applicability to cover NO_X SIP Call non-EGUs, for the reasons discussed elsewhere in this preamble.

In contrast, in the CAIR trading programs, a NO_X SIP Call state could expand the applicability of the CAIR ozone-season NO_X trading program in the state in order to include all units subject to the NO_X Budget Trading Program under the NO_X SIP Call. A number of states chose to expand the CAIR ozone-season NO_X trading program applicability in this way. The transition from CAIR to the Transport Rule is discussed in section IX.A.2 and SIPs are discussed in section X of this preamble.

Structure of the remedy. The CAIR FIPs (and CAIR model trading rules adopted by a number of states in their CAIR SIPs) implemented reductions through SO_2, annual NO_X, and ozone-season NO_X interstate emission trading programs covering primarily large EGUs. The owners and operators of a covered source could buy allowances

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from or sell allowances to other covered sources (or other market participants) and were required to surrender allowances equal to the source's emissions for each compliance period. CAIR's trading programs did not impose limitations on the aggregate emissions from covered units within any covered state.

The Transport Rule FIPs will also achieve the required reductions through SO_2, annual NO_X, and ozone-season NO_X interstate trading programs. However, in contrast to CAIR and for the reasons discussed in section VII of this preamble, the Transport Rule FIPs include assurance provisions specifically designed to ensure that no state's emissions will exceed that state's emission budget plus the variability limit, *i.e.,* the state's assurance level.

Another difference in the remedy structure is in the design of the SO_2 trading programs. In CAIR all of the states required to reduce SO_2 emissions were grouped together in one SO_2 trading program with no restriction on the use of SO_2 allowances from any state in the program by any source in the program. In contrast, and for the reasons discussed in section VI of this preamble, the Transport Rule divides states required to reduce SO_2 emissions into two groups with emission reduction requirements of different stringency starting in 2014 (SO_2 Group 1, whose reduction requirements become more stringent starting in 2014, and SO_2 Group 2, whose reduction requirements in 2014 do not change). A covered source may only use for compliance—with the requirements to hold allowances covering emissions and, if applicable, to surrender allowances under the assurance provisions—an SO_2 allowance issued for the SO_2 Group in which the source's state is included. In other words, an SO_2 Group 1 source may only use a SO_2 Group 1 allowance for compliance, and likewise an SO_2 Group 2 source may only use a SO_2 Group 2 allowance for compliance.

Provisions for early reductions. CAIR included provisions for covered sources to make early reductions prior to the start of CAIR's SO_2 and NO_X trading programs, bank emission allowances, and carry banked allowances into its trading programs. In contrast, the Transport Rule does not include provisions for covered sources to carry over any allowances (*i.e.,* Title IV SO_2 allowances or CAIR annual or ozone-season NO_X allowances) into the Transport Rule trading programs. EPA's reasons for not allowing the use of banked Title IV SO_2 allowances or CAIR annual or ozone-season NO_X allowances in the Transport Rule trading programs are discussed in the next section.

Provisions for SIPs. The following is a summary of the key differences between the Transport Rule and CAIR provisions for SIPs. A more detailed discussion of Transport Rule SIPs is in section X of this preamble.

The SIP provisions in the Transport Rule and CAIR are very similar. Both include provisions that allow states to submit SIP revisions (referred to as full SIPs) that replace an applicable FIP trading program with a comparable SIP trading program that has certain limited differences from the FIP trading program. Similarly, both rules include provisions that allow states to submit SIP revisions (referred to as abbreviated SIPs) that may modify certain limited provisions in the FIP trading program, which remain in place. Inclusion of this provision in the Transport Rule allows a state to modify certain elements of a Transport Rule FIP trading program in order to better meet the needs of the state. Both the Transport Rule and CAIR allow full or abbreviated SIPs that involve one or more applicable FIP trading programs. However, there are a few differences.

In particular, under the Transport Rule, states may submit SIP revisions under which the state determines allocations for the applicable trading program using either full or abbreviated SIP revisions. States could submit similar revisions under CAIR. Under the Transport Rule, the state may use the same allocation methodology as that currently used in the Transport Rule FIP trading program or some other allocation methodology. However, the Transport Rule specifies certain requirements that must be met concerning, for example, the timing of such allocation determinations, and expressly allows allowance auctions to be used. CAIR did not include similar provisions. Further, the SIP submission deadlines, allocation submission, and allocation recordation dates are different between the Transport Rule and CAIR. The Transport Rule SIP submission deadlines and allocation recordation dates are discussed in section X of this preamble.

In addition, both the Transport Rule and CAIR include provisions that allow states to submit SIP revisions under which the state expands the general applicability provisions of the ozone-season NO_X trading programs to cover certain units subject to the NO_X SIP Call. However, for the reasons discussed elsewhere in this preamble, this flexibility is more limited in the Transport Rule than it was in CAIR.

While CAIR allowed states to adopt, through full or abbreviated SIPs, opt-in provisions, the Transport Rule does not allow for opt-in provisions. The reasons for this are discussed in section VII.B of this preamble.

Finally, neither full nor abbreviated SIPs can replace FIP provisions that apply to units in Indian country within the borders of a state. For example, the FIPs include, for states within whose borders Indian country is located, an Indian country new unit set-aside. For states not having Indian country within their borders, abbreviated SIPs are limited to replacing the allowance allocation provisions of the FIPs for the state involved and may replace some or all of those provisions. However, for states having Indian country within their borders, abbreviated SIPs cannot replace the FIP provisions for the Indian country new unit set-aside. Similarly, for states not having Indian country, full SIPs can replace an entire FIP, but, in doing so, can only change the allowance allocation provisions. For states having Indian country, full SIPs can replace the FIPs except for the Indian country new unit set-aside provisions, which will remain under the applicable FIPs, and, like the abbreviated SIPs, can only change the allowance allocation provisions that are replaced.

Details of the Transport Rule provisions for abbreviated and full SIP revisions, including deadlines for submission to EPA, are discussed in section X of this preamble.

2. Transition From the Clean Air Interstate Rule to the Transport Rule

The Transport Rule replaces CAIR and its associated trading programs. This section elaborates on areas of transition from CAIR to the Transport Rule.

a. Sunsetting of CAIR, CAIR SIPs, and CAIR FIPs

The proposal explained that, for control periods in 2012 and thereafter, CAIR, CAIR SIPs, and CAIR FIPs would be replaced entirely by the Transport Rule provisions. The proposal outlined implementation of the sunsetting of CAIR and CAIR FIPs, through revisions to CAIR, §§ 51.123 and 51.124, and the CAIR FIPs, §§ 52.35 and 52.36. For the control period in these years, the CAIR trading programs would not continue, and the Administrator would not carry out any of the functions established for the Administrator in the CAIR model trading rule, the CAIR FIPs, or any state trading programs approved under CAIR. Offset and automatic penalty provisions under CAIR would not apply to excess emissions for 2011 control periods.

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Also discussed were the processes for modifying provisions in Part 52 reflecting state-specific CAIR SIP and CAIR FIP requirements, which would vary depending on whether a state has an approved CAIR SIP or a CAIR FIP. The proposal further explained that sources in some states covered by CAIR or the CAIR FIPs would not be subject to the Transport Rule and that to the extent that CAIR reductions were needed or relied upon to satisfy other SIP requirements, states might need to find alternative ways to satisfy requirements for their SIPs.

EPA is finalizing regulatory changes to sunset CAIR and the CAIR FIPs. The final rule revises the general CAIR and CAIR FIP provisions in Parts 51 and 52 applicable to all CAIR states. For control periods in 2012 and thereafter, the Administrator rescinds the determination that states must meet SIP requirements under CAIR, and the requirements of the CAIR FIPs are not applicable. Further, with regard to these control periods, the Administrator will no longer carry out any of the functions established for the Administrator in the CAIR model trading rule, the CAIR FIPs, or any state trading programs approved under CAIR with the exception of enforcing the provisions for the previous control periods, if necessary.

For the reasons discussed in the proposed rule preamble (75 FR 45337), CAIR allowances allocated for these control periods cannot be used in any CAIR trading program and, as discussed below, in any Transport Rule trading program. Specifically, for the reasons discussed in the proposed rule, offset and automatic allowance penalty provisions in the CAIR trading programs will not be applied to 2011 control period excess emissions, which will remain subject to discretionary civil penalties under CAA section 113. EPA still retains all enforcement options for excess emissions during the 2011 control period. CAIR allowances allocated for 2012 and thereafter are not usable in any CAIR or Transport Rule trading program. In light of that fact, in order to prevent any confusion by owners and operators and other members of the public concerning the status of such allowances, the final rule provides that, within 90 days after publication of the final Transport Rule, the Administrator will remove post-2011 CAIR annual NO_X and ozone-season allowances from the Allowance Tracking System.

The CAIR SO_2 trading program, of course, uses Acid Rain allowances, which will remain in the Allowance Tracking System because they were created by CAA Title IV and continue to be usable in the Acid Rain Program.

The final rule also adopts the discussion in the proposed rule concerning state-specific Part 52 provisions concerning CAIR (75 FR 45337–38). With regard to Part 52 provisions reflecting EPA's adoption of ongoing CAIR FIPs for some individual states, the final rule revises the CAIR FIP provisions to make them inapplicable to control periods in 2012 and thereafter and to require the Administrator to remove from the Allowance Tracking System, CAIR allowances for these control periods. The final, state-specific CAIR FIP provisions in Part 52 essentially echo the language in the final, general CAIR provisions in Part 52 discussed above. In making the CAIR FIP provisions inapplicable to control periods in 2012 and thereafter, the final, state-specific provisions sunset the applicable CAIR FIP trading programs whether or not the CAIR FIPs were revised by approved, abbreviated CAIR SIPs. (Under CAIR, abbreviated CAIR SIPs were adopted by certain states so that states, rather than EPA, made NO_X allowance allocations.) Consequently, states with approved, abbreviated CAIR SIPs will not need to revise their abbreviated CAIR SIPs in order to sunset the CAIR trading programs to which these abbreviated SIPs applied. Thus, although such abbreviated SIPs may remain in the state SIPs, they will have no force and effect, once the CAIR FIPs sunset.

With regard to Part 52 provisions reflecting EPA's approval of full CAIR SIPs submitted to EPA by many individual states, the Court's *North Carolina* decision essentially overrides these Agency approvals of individual CAIR SIPs. (Under CAIR, full CAIR SIPs were adopted by certain states to replace CAIR FIPs and continue participation through the CAIR SIPs in the CAIR trading programs.) The Court found CAIR to be illegal and only allowed it to remain in effect temporarily. For this reason, the CAIR SIPs though approved, can have no force and effect once CAIR is replaced by this rule. For this reason, although the proposed rule indicated that states would need to submit SIP revisions to, among other things, make the CAIR SIPs inapplicable to control periods after 2011, the final rule does not require states to take any actions to revise their full or abbreviated CAIR SIPs. For states covered by CAIR or CAIR FIPs that are not subject to the Transport Rule and have relied on CAIR reductions to satisfy other SIP requirements, EPA will discuss with states alternative ways to satisfy requirements for those SIP requirements, *e.g.,* through intrastate cap and trade programs that require the level of reductions on which the state has recently relied.

b. NO_X SIP Call Units

The NO_X Budget Trading program was used by states to reduce ozone-season NO_X emissions from EGUs and large non-EGUs under NO_X SIP Call requirements. The program started in 2003 and ended in 2008. Under CAIR, a state subject to the NO_X SIP Call was allowed to expand the applicability of the CAIR ozone-season NO_X trading program in the state in order to include all units subject to the NO_X Budget Trading Program under the NO_X SIP Call and thereby to continue to meet the state's NO_X SIP Call requirements. Fourteen states chose to expand the CAIR ozone-season NO_X applicability in this way, while six states chose not to expand the applicability and instead to meet their NO_X SIP Call obligations in other ways. EPA proposed to not allow this expansion in applicability for the Transport Rule, primarily because these sources as a group did not actually reduce emissions for the NO_X Budget Trading Program or CAIR. EPA took comment on the proposed approach.

Several commenters generally advocated allowing, at state discretion, all NO_X Budget Trading Program units to be regulated under the Transport Rule ozone-season NO_X trading program. Some also questioned how states would otherwise satisfy NO_X SIP Call requirements for these units. Some commenters argued that some units did in fact make emission reductions in the NO_X Budget Trading Program, but did not provide information on specific units.

The final rule provides states an option to expand the general applicability provisions of the Transport Rule ozone-season NO_X trading program to cover small EGUs, but not other units in the NO_X SIP Call. Specifically, consistent with the comments, EPA determined that it is appropriate to allow states to expand the applicability of the Transport Rule ozone-season NO_X trading program to include units serving a generator with a nameplate capacity equal to or greater than 15 MWe producing electricity for sale. This will allow states with NO_X SIP Call obligations to meet those requirements with respect to these small EGUs. These units can be brought into the program through abbreviated or full Transport Rule SIPs. However, if a state chooses to expand the general applicability provisions, the state Transport Rule ozone-season NO_X budget cannot be increased. EPA believes that the level of

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emissions from small EGUs is sufficiently small that the existing Transport Rule state budget can accommodate these units. This is consistent with the approach taken in the NO_X Budget Trading Program, where the states that added these small EGUs did not increase their NO_X SIP Call EGU budgets. This also removes concern (expressed in the proposed rule) that increasing state budgets in the Transport Rule ozone-season NO_X trading program, as part of the expansion of the applicability provisions to include small EGUs, would jeopardize elimination of a state's significant contribution to nonattainment and interference with maintenance.

With regard to large non-EGUs that were included in the NO_X Budget Trading Program (the remainder of the sources in the NO_X Budget Trading Program), the final Transport Rule, like the proposed rule, does not allow expansion of the general applicability provisions for the ozone-season NO_X trading program to include such units. As explained in the proposed rule (75 FR 43340), while some of these units may have installed controls around the start of the NO_X Budget Trading Program, EPA analysis shows that, as a group, these units did not collectively reduce emissions, their current emission rates are nearly identical to their emission rates before the start of the NO_X Budget Trading Program, and their allocations are about twice their emissions, with the result that the excess allocations were sold to covered EGUs.[117] Moreover, EPA believes that there are little or no emission reductions available by non-EGUs at the cost thresholds used in the final rule and so no basis for developing non-EGUs state budgets reflecting the elimination of significant contribution to nonattainment and interference with maintenance. For these reasons, the final rule allows states to expand the ozone-season NO_X trading program to cover small EGUs that were in the NO_X Budget Trading Program, but not to cover large non-EGUs that were in that program. As explained in the proposed rule, if a state were to do so, emissions from these units could jeopardize elimination of the state's significant contribution to nonattainment or interference with maintenance. *See* 75 FR 45340. For states that relied on large non-EGUs for emission reductions required by the NO_X SIP Call, EPA will assist in identifying ways to ensure continued, future compliance with the NO_X SIP Call requirements.

c. Early Reduction Provisions

Substantial emission reductions have occurred as a result of previous emission trading programs, under both Title IV and CAIR. This has lead to substantial ''banks'' of allowances (*i.e.,* holdings of unused allowances allocated for years before the programs sunset) in each of the CAIR programs. In the proposal, EPA requested comment on whether to allow banked CAIR allowances to be used in the Transport Rule trading programs. EPA recognizes the importance of continuity in emission trading programs as a general principle. However, for the reasons explained below, EPA has decided not to allow banked CAIR allowances to be used in any of the Transport Rule trading programs. (1) SO_2 Allowance Bank

The bank of Title IV allowances was more than 12 million tons at the end of 2009. This bank is the result of emission reductions under the Title IV Acid Rain Program. Under the CAIR SO_2 trading program, EPA allowed banked (as well as future year) Title IV allowances to be used in the CAIR SO_2 trading program—in lieu of being used in the Acid Rain Program—for compliance with the requirement to hold allowances covering SO_2 emissions. This approach encouraged early reductions for the CAIR SO_2 trading program, but was held to be unlawful in *North Carolina.*

In the proposed rule, EPA took comment on whether sources should be allowed to use banked Title IV allowances in the Transport Rule SO_2 program. EPA proposed to not allow the use of Title IV allowances either as the basis for allocating Transport Rule SO_2 allowances or directly for compliance with allowance-holding requirements, in part, because EPA was concerned that those approaches would be perceived as inconsistent with the requirements of CAA section 110(a)(2)(D)(i)(I) as interpreted by the Court in *North Carolina. See* 75 FR 45338–39.

A number of commenters advocated that EPA recognize Title IV allowance holdings in the Transport Rule, either by allowing full or limited carryover of the allowances or by allocating all or a portion of the Transport Rule SO_2 allowances based on Title IV allowance holdings. Other commenters agreed with EPA's assessment that allowing Title IV allowance carryover in the Transport Rule is inconsistent with *North Carolina* and that any linkage of Transport Rule allocations with Title IV allowance holdings would carry unnecessary, significant legal risk. Therefore, for the reasons explained above and in the proposal, EPA has decided not to permit sources to use Title IV allowances for compliance with the Transport Rule SO_2 trading programs.

In addition, unlike CAIR, in the Transport Rule, EPA decided not to base allocation of Transport Rule SO_2 allowances on the specific distribution of existing Title IV allowances. Title IV allowances continue, of course, to be usable for compliance in the Acid Rain Program.[118]

(2) NO_X Allowance Banks

In the proposed rule, EPA estimated that the CAIR ozone-season NO_X bank would contain over 600,000 allowances and the CAIR annual NO_X bank would contain about 720,000 allowances after completion of true-up of allowance holdings and emissions for 2011. EPA considered the alternatives of allowing or not allowing pre-2012 CAIR NO_X allowances and CAIR ozone-season NO_X allowances to be used in the Transport Rule NO_X trading programs.

EPA also described and requested comment on several possible approaches for handling banked pre-2012 CAIR NO_X allowances in the Transport Rule NO_X trading programs and the pros and cons of each (75 FR 45339):

- Allow all such banked CAIR allowances to be brought into the Transport Rule NO_X programs, make the assurance provisions effective starting in 2012, and rely on the assurance provisions to ensure that each state continues to eliminate all of its significant contribution to nonattainment and interference with maintenance;
- Allow only a limited amount of banked pre-2012 CAIR allowances to be brought into the Transport Rule NO_X programs;
- Factor the bank into the calculation of state NO_X budgets by reducing the state NO_X budgets to take account of the banked pre-2012 CAIR allowances; and
- Do not allow the use of any banked pre-2012 CAIR allowances in the Transport Rule NO_X programs.

EPA proposed the last of these approaches and requested comment on all of the described approaches or suggestions on other ways to handle banked pre-2012 CAIR allowances in the Transport Rule NO_X programs.

[117] Although the proposed rule discussed the EPA analysis in the context of considering the treatment of both small EGUs and large non-EGUs from the NO_X Budget Trading Program, the analysis actually addresses, and draws conclusions about emission reductions, emission rates, and allowance allocations concerning only large non-EGUs.

[118] The Title IV allowance bank is expected to be about 14 million tons at the beginning of 2012.

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- Many commenters advocated allowing the carryover of CAIR NO_X allowances to the Transport Rule. Reasons given included: preservation of early reduction investments; need for market continuity; increased flexibility during program start up and early years of the programs; preservation of the credibility of, and certainty under, trading approaches; and the lack of a prohibition in *North Carolina* of carryover of CAIR NO_X allowances. Commenters also suggested that surrender ratios be used to limit the amount, and negative effects, of a carryover.
- Many other commenters were against allowing CAIR NO_X allowance carryover into the Transport Rule. Reasons given included: unnecessary, significant legal risk; concerns about the efficacy of the Transport Rule if state budgets are supplemented by a carryover; and differences in the nature of the programs (the NO_X Budget Trading Program, which addressed the 1-hour ozone NAAQS, and the CAIR ozone-season NO_X trading program, which addressed the 1997 8-hour ozone NAAQS and was reversed in *North Carolina*) under which the allowances were banked, and the Transport Rule ozone-season NO_X trading program, which addresses the 1997 8-hour ozone NAAQS.

For the reasons explained below, after evaluating all comments on this issue, EPA decided not to allow the use of CAIR NO_X allowances in the Transport Rule NO_X trading programs. EPA reevaluated the estimated size of the potential carryover (allowances that will remain unused in the CAIR programs at the end of 2011 compliance periods), taking into account 2010 emissions. EPA estimates that more than 440,000 CAIR ozone-season NO_X allowances will remain and that more than 460,000 CAIR annual NO_X allowances will remain at the end of the 2011 compliance periods. EPA considered whether to allow these CAIR ozone-season NO_X and CAIR annual NO_X allowances to be used in the Transport Rule NO_X trading programs. The CAIR ozone-season NO_X allowances expected to remain unused represent nearly three-quarters of aggregate state ozone-season NO_X budgets [119] in a single year under the final Transport Rule. The allowances expected to remain unused in the annual NO_X program represent more than one-third of aggregate state annual NO_X budgets in a single year under the Transport Rule. As discussed in the proposal, if these allowances were carried over in addition to the Transport Rule state budgets, EPA could not be assured that significant contribution to nonattainment or interference with maintenance would be eliminated. EPA therefore rejects any approach under which all banked CAIR NO_X allowances would be added to the Transport Rule trading programs on top of each state's annual NO_X and/or ozone-season NO_X budgets.

In response to public comments, EPA considered whether the Transport Rule trading programs should allow some form of exchange of banked CAIR annual NO_X and ozone-season allowances for new Transport Rule NO_X allowances within each state's annual NO_X and/or ozone-season budgets, respectively. However, EPA believes that this type of approach carries substantial legal and technical problems. First, the state-by-state distribution of CAIR NO_X allowances resulted from the methodology applied by EPA in CAIR of using fuel factors to set the total amounts of allowance allocations in each state (*i.e.*, the state NO_X budgets). The CAIR NO_X allowance banks therefore are—at least in part—the result of this methodology, which was reversed in *North Carolina. See* North Carolina, 531 F.3d at 918–22. Thus, EPA did not use fuel factors in developing the Transport Rule state budgets. However, EPA is concerned that the distribution of some or all Transport Rule NO_X allowances through exchanges of banked CAIR NO_X allowances for Transport Rule NO_X allowances would blur the bright line between the methodology used for setting budgets in the Transport Rule and the methodology used for setting budgets in CAIR that was rejected by the Court. At least to some extent, the parties that were advantaged under EPA's budget-setting methodology in CAIR would continue to have an advantage under the Transport Rule by receiving more Transport Rule NO_X allowances. EPA therefore believes that allowing exchange of banked CAIR NO_X allowances for Transport Rule NO_X allowances carries significant legal risk.

Second, establishing a procedure for exchanging banked CAIR NO_X allowances for Transport Rule NO_X allowances within each state's budget would mean that Transport Rule NO_X allowances could not be allocated until after completion of the process for determining compliance with allowance-holding requirements for 2011 in the CAIR NO_X trading programs. This process cannot begin until after the allowance transfer deadline for the 2011 control periods (*i.e.*, March 1, 2012 for the CAIR annual NO_X program and November 1, 2011 for the CAIR ozone-season NO_X program) and will not likely be completed until mid-2012. At that time, EPA could begin the procedure of implementing, state-by-state, the exchanges of the remaining CAIR NO_X allowance banks held by parties (owners and operators, brokers, and other entities) for some or all of the allowances in the state NO_X budgets for 2012. The portion of each state budget that would be used up by such exchanges would likely vary from state to state. The resulting delay, and uncertainty about the unit-by-unit amounts, of Transport Rule NO_X allowance allocations for 2012 would undermine Transport Rule allowance market liquidity, significantly disrupt planning by owners and operators for compliance with allowance-holding requirements for the 2012 control periods, and likely impose increased compliance costs under the Transport Rule NO_X trading programs or impact the ability to comply with the 2012 limits.

In light of the specific circumstances in this case and the above-described legal and technical problems that would result from a carryover of CAIR NO_X allowances into the Transport Rule trading programs, the final rule does not allow any such carryover. EPA agrees that, as a general principle, it is desirable to provide continuity between sequential regulatory programs involving emission trading and thereby to ensure that allowances in the past program continue to have some value in the new program. Balancing the general desirability of providing program continuity against the potential negative consequences of a carryover in, and the specific circumstances of, this case, EPA concludes that the carryover of banked CAIR NO_X allowances into the Transport Rule trading programs should not be allowed. EPA notes that, in this case, it signaled the possibility that it would take such an approach in order to provide markets with full information and avoid unnecessary disruptions. After CAIR was remanded by the Court in *North Carolina,* 550 F.3d 1176, in December 2008, EPA was concerned about the future status of CAIR NO_X allowances and consequently advised the public—through a statement posted on the EPA Web site in March, 2009—that ''EPA's continued recording of CAIR NO_X allowances does not guarantee or imply that any allowances will continue to be usable for

[119] This analysis is for all states identified to be contributing significantly to nonattainment or interfering with maintenance. When the analysis is conducted using the aggregate state budgets for only those states for which we are finalizing ozone season requirements in this rule, the percentage increases.

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compliance after a replacement rule is finalized or that they will continue to have value in the future.'' [120] EPA believes its decision to disallow carryover of banked allowances here reflects the specific factors in this case and should not be treated as setting any precedent for the treatment, in any future trading programs, of any past trading program's banked allowances.

However, EPA notes that, under the CAIR ozone-season NO_X trading program, where unused allowances were carried forward from the preceding NO_X Budget Trading Program, and under the CAIR annual NO_X trading program, where extra allowances (from the compliance supplement pool) were allocated for early reductions made during the NO_X Budget Trading Program, the vast majority of allowance allocation decisions were made by the states administering these programs. Moreover, a number of states did not allocate CAIR allowances to their sources using fuel adjustment factors, whose use the Court rejected in *North Carolina* in connection with EPA's setting of state NO_X emission budgets.

In light of the general desirability of providing continuity between state programs, states may want to address the CAIR NO_X banks when developing, in SIP revisions, the Transport Rule allowance allocations for control periods after 2012. EPA encourages each state that wants to allocate Transport Rule NO_X allowances through SIP revisions to consider using information on the CAIR NO_X allowance banks that will remain after 2011. Any such allowance allocations, of course, must be within the respective state's NO_X trading budget, and must be submitted to EPA within the applicable submission deadlines, established in the final rule for the control periods for which the allocations are made. The Agency intends to contact states concerning the desirability of holding a workshop to discuss issues related to state allowance allocations.

B. Interactions With NO_X SIP Call

The proposed rule explained that states covered by both the NO_X SIP Call and the Transport Rule would be required to comply with the requirements of both rules and that the Transport Rule would not preempt or replace the requirements of the NO_X SIP Call. Most, but not all, NO_X SIP Call states would be included in the Transport Rule. The proposed rule further explained that the Transport Rule ozone-season NO_X trading program would achieve the emission reductions required by the NO_X SIP Call from EGUs serving generators with a nameplate capacity greater than 25 MW and producing electricity for sale in most NO_X SIP Call states. (This would not be the case, of course, for those NO_X SIP Call states not covered by the Transport Rule.)

The NO_X SIP Call states used the NO_X Budget Trading Program to comply with the NO_X SIP Call requirements for EGUs serving a generator with a nameplate capacity greater than 25 MW and large non-EGUs with a maximum rated heat input capacity greater than 250 mmBtu/hour. (In some states, EGUs serving a generator with a nameplate capacity of 25 MW or less were also included in the NO_X Budget Trading Program as a carryover from the Ozone Transport Commission NO_X Budget Trading Program.) EPA stopped administering the NO_X Budget Trading Program under the NO_X SIP Call after the completion of compliance activities related to the 2008 ozone-season control period, and states used other mechanisms to comply with the NO_X SIP Call requirements.

The proposal further explained that, if EPA promulgated a final rule that did not allow the expansion of the Transport Rule to NO_X Budget Trading Program units, any state that allowed these units to participate in the CAIR ozone-season NO_X trading program would need to submit a SIP revision to address the state's NO_X SIP Call requirement for the reductions. The proposal also explained that states in the CAIR ozone-season NO_X trading program or the NO_X Budget Trading Program that would not be in the Transport Rule ozone-season NO_X trading program would need to submit SIP revisions addressing the NO_X SIP Call requirements for any emission reductions (by EGUs and non-EGUs) addressed in the NO_X Budget Trading Program and not addressed in some other way. *See* 75 FR 45340–41.

As discussed elsewhere in this preamble, the final Transport Rule allows states to expand the general applicability provisions of the Transport Rule ozone-season NO_X trading program to include small EGUs, which were included by some states in the NO_X Budget Trading Program, but not for large non-EGUs, which were included in the NO_X Budget Trading Program. This will allow states with NO_X SIP Call obligations to meet those requirements with respect to small EGUs brought into the Transport Rule trading program, but not with regard to large non-EGUs.

With the issuance of the final Transport Rule, NO_X SIP Call requirements remain in place. *See* 40 CFR 51.121. EPA is not changing any of the NO_X SIP Call requirements. The NO_X SIP Call generally requires that states choosing to rely on large EGUs and large non-EGUs for meeting NO_X SIP Call emission reduction requirements must establish a NO_X mass emissions cap on each source and require Part 75, subpart H monitoring. As an alternative to source-by-source NO_X mass emissions caps, a state may impose NO_X emission rate limits on each source and use maximum operating capacity for estimating NO_X mass emissions or may rely on other requirements that the state demonstrates to be equivalent to either the NO_X mass emissions caps or the NO_X emission rate limits that assume maximum capacity. Collectively, the caps or their alternatives cannot exceed the portion of the state budget for those sources. *See* 40 CFR 51.121(f)(2) and (i)(4). EPA will work with states to ensure that NO_X SIP Call obligations continue to be met (*e.g.,* through intrastate cap and trade programs that require the level of reductions on which the state has recently relied).

C. Interactions With Title IV Acid Rain Program

The final rule does not affect any Acid Rain Program requirements. Acid Rain Program requirements are established independently in Title IV of the CAA and are not replaced by the Transport Rule. Title IV sources that are subject to final Transport Rule provisions still need to continue to comply with all Acid Rain provisions. Title IV SO_2 and NO_X requirements continue to apply independently of the Transport Rule provisions. For the reasons explained above, Title IV SO_2 allowances are not allowed to be used in the Transport Rule trading programs. Similarly, Transport Rule SO_2 allowances are not usable in the Acid Rain Program.

The final Transport Rule does not include any opt-in unit provisions in the FIPs and does not allow SIP revisions to include opt-in unit provisions in the Transport Rule trading programs. Consequently, no sources, including those that have opted in to the Acid Rain Program, can opt-in to the Transport Rule trading programs.

There will likely be changes to emissions at some Acid Rain units outside of the Transport Rule area as a result of the transition from CAIR to the Transport Rule. Namely, emissions at some non-Transport Rule Acid Rain

[120] *http://epa.gov/airmarkets/business/cairallowancestatus.html*. EPA posed similar statements in the on-line systems for trading CAIR NO_X allowances. *See* 40 CFR 96.102 and 96.302 (definitions of ''CAIR NO_X Allowance Tracking System'' and ''CAIR NO_X Ozone Season Allowance Tracking System'').

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units in the states that border the Transport Rule states may increase because of potential load-shifting from units in Transport Rule states and because of a potential decrease in the Title IV allowance price. There is a discussion of possible emission increases in non-covered states in section VI.C of this preamble.

D. Other State Implementation Plan Requirements

In this final action, EPA has not conducted any technical analysis to determine whether compliance with the Transport Rule would satisfy RACT requirements for EGUs in any nonattainment areas, or Regional Haze BART-related requirements. For that reason, EPA is neither making determinations nor establishing any presumptions that compliance with the Transport Rule satisfies any RACT or BART-related requirements for EGUs. Based on analyses that states conduct on a case-by-case basis, states may be able to conclude that compliance with the Transport Rule for certain EGUs fulfills nonattainment area RACT requirements. EPA intends to undertake a separate analysis to determine if compliance with the Transport Rule would provide sufficient reductions to satisfy BART requirements for EGUs in accordance with Regional Haze Rule requirements for alternative BART compliance options as soon as practicable following promulgation of the Transport Rule.

X. Transport Rule State Implementation Plans

EPA proposed (75 FR 45342) FIPs setting state-specific emission reduction requirements for each upwind state covered by the proposed Transport Rule and with respect to one or more of three air quality standards—the 1997 annual $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the 1997 ozone NAAQS. In CAIR, EPA allowed the states to replace the CAIR FIP with SIPs and provided substantial flexibility. In the proposed Transport Rule, EPA proposed to allow similar flexibility to states for addressing the CAA section 110(a)(2)(D)(i)(I) transport issues through a SIP. EPA proposed to allow a state to submit a SIP for the ozone requirements only, for the $PM_{2.5}$ requirements only, or for both the ozone and the $PM_{2.5}$ requirements with the specific quantity of emission reductions necessary for a state's SIP determined based on the state emission budgets provided in the final Transport Rule.

EPA received comments suggesting that if the proposal's remedy were finalized, EPA should allow states to replace the FIP allowance allocation provisions in the proposed Transport Rule trading programs by state-developed allocation provisions. Commenters referenced the two alternatives provided to states in the CAIR trading programs where: (1) EPA adopted a rule and model trading regulations under which states that adopted, as state SIP trading programs, the model regulations (with only certain limited changes allowed, *e.g.,* in the allocation provisions) could participate in the EPA-administered CAIR trading programs; and (2) EPA adopted a rule allowing states to adopt in SIPs provisions replacing only certain provisions in the CAIR FIPs (*e.g.,* the allocation provisions) and to remain in the CAIR trading programs under the CAIR FIPs. Under both approaches, the covered units in the state participated in the CAIR trading programs, albeit with state-, rather than EPA-, determined allocations. Comments on the Transport Rule proposal supported these two types of approaches for allowing states to replace EPA allocations under the proposed Transport Rule trading programs by state allocations. EPA requested additional comment on this topic in the NODA published January 7, 2011 (76 FR 1109).

Two approaches with associated deadlines were explained in the NODA. Under the first approach, EPA would adopt new provisions, as part of the proposed Transport Rule FIP that would allow a state to submit a SIP (referred as an abbreviated SIP) that would modify specified provisions of the proposed Transport Rule FIP trading programs. Specifically, the abbreviated SIP would substitute state allocation provisions for control periods in years after 2012, applicable to one or more of the proposed Transport Rule FIP trading programs that apply to the state. The NODA explained which specific provisions in the FIP could be replaced. If the state allocation provisions met certain requirements and the abbreviated SIP did not change any other provisions in the respective proposed Transport Rule FIP trading program, then EPA would approve the abbreviated SIP. In the substitute state allocation provisions, the state could allocate allowances to Transport Rule units (whether existing or new units) or other entities (such as renewable energy facilities) or could auction some or all of the allowances. The NODA went on to describe the requirements for EPA approval of an abbreviated SIP (76 FR 1119) including that the total amount of allowances allocated and auctioned each year could not exceed the applicable budget; allocations and auction results would need to be reported to EPA by the permitting authority (usually the state) by particular dates prior to the applicable control period depending on whether allowances were going to existing or new sources; the reported allocations and auction results could not be changed; and no other provisions of the FIP would be changed.

Under the second approach, EPA would adopt a new rule that would provide that, if a state submitted a SIP (referred to as a full SIP) that adopted trading program regulations meeting certain requirements for control periods in years after 2012, then EPA would approve the full SIP as correcting the deficiency under CAA section 110(a)(2)(D)(i)(I) in the state's SIP that was the basis for issuance of the comparable proposed Transport Rule FIP. In the state allocation provisions, the state could allocate allowances to Transport Rule units (whether existing or new units, except for opt-in units) or other entities (such as renewable energy facilities) or could auction allowances. Upon EPA approval of a state's full SIP, the state's SIP-based trading program would be integrated with the comparable FIP-based Transport Rule trading program (whether or not modified by an abbreviated SIP) covering other states. Moreover, covered sources in the state could participate in the integrated trading program, and the allowances issued under the SIP-based state trading program would be interchangeable with the allowances issued in the comparable FIP-based Transport Rule trading program.

The NODA went on to describe the limited changes that states could make under the full SIP option. Only allocation provisions could be modified with the same requirements as for abbreviated SIPs, including, among other things, that the total amount of allowances allocated each year could not exceed the applicable budget and that allocations would need to be reported to EPA by the permitting authority (usually the state) by particular dates prior to the applicable control period depending on whether allowances were going to existing or new sources.

The NODA also discussed the option for states to submit SIPs using emission reduction approaches other than the proposed Transport Rule trading programs to correct the deficiency under CAA section 110(a)(2)(D)(i)(I) in the state's SIP. EPA would review on a case-by-case basis SIPs using such alternative approaches (76 FR 1120).

Suggested deadlines for abbreviated and full SIPs were given in tables in the

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NODA (76 FR 1120). These deadlines generally required states to submit SIPs about 2 years ahead of a particular control period for which state allocations would apply in order to give EPA time to review and approve the SIP and record allowances.

Most commenters on the NODA supported state allocation options, within the preferred FIP remedy, that would replace FIP allocations with SIP-based state allocations.

In the final rule, EPA adopts, with some revisions, both of the approaches described in the January 7, 2011 NODA. Under the first approach, a state may submit an abbreviated SIP that modifies a final Transport Rule FIP trading program in only a limited way (*i.e.,* by replacing the allowance allocation provisions in §§ 97.411(a) and (b)(1) and 97.412(a) for the annual NO_X trading program, §§ 97.511(a) and (b)(1) and 97.512(a) for the ozone-season NO_X trading program, §§ 97.611(a) and (b)(1) and 97.612(a) for the SO_2 Group 1 trading program, and §§ 97.711(a) and (b)(1) and 97.712(a) for the SO_2 Group 2 trading program). In the state's replacement provisions, the state may allocate allowances to Transport Rule units (whether existing or new units) [121] or other entities (such as renewable energy facilities) or may auction allowances. Additionally, state SIPs can address one or all of the pollutants addressed by the FIPs. For $PM_{2.5}$, EPA is finalizing the flexibility for a state SIP to address either SO_2 or NO_X, or both. Further, if a state is required to make ozone-season and annual NO_X reductions, the SIP could address either ozone-season or annual NO_X emissions, or both. In other words, states can replace provisions in all FIPs that apply or some subset of the FIPs that apply to a particular state, and leave in place the FIPs for the requirements not addressed by a SIP.

Further, EPA will approve the abbreviated SIP only if the state replacement for the Transport Rule FIP allocation provisions meets certain requirements and the abbreviated SIP does not change any other provisions in the Transport Rule FIP trading program. For EPA approval, the state allocation and, where applicable, auction provisions (and any accompanying definitions of terms applying only to terms as used in these provisions) must meet the following requirements. First, the provisions must provide that, for each year for which the state allocation and, where applicable, auction provisions will apply, the total amount of control period (annual or ozone-season) allowances allocated and, where applicable, auctioned in accordance with these provisions cannot exceed the applicable state budget (less any applicable Indian country new unit set-aside, which will continue to be administered by EPA) for that year under the relevant Transport Rule FIP trading program.

Second, to the extent the state provisions provide for allocations for, or auctions open to, existing units, the provisions must require that the state or the permitting authority under title V of the CAA for the state submit to the Administrator final allocations and, if any auction is to be held, final auction results in accordance with a schedule of deadlines discussed below. To the extent the provisions provide for allocations for or auctions open to new units or any other entities, the provisions must require that the permitting authority submit to the Administrator final allocations and, if applicable, auction results by July 1 of the year of the control period for which the allowances will be distributed. The allocation and auction results must be final and cannot be subject to modification (*e.g.,* through an allowance surrender adjusting the allocation or auction results).

As noted above, the state's submission to the Administrator of allocations or auction results with regard to existing units must meet a specified schedule of deadlines. These submission deadlines reflect, and are necessarily coordinated with, the deadlines for recordation by the Administrator of allowance allocations and any auction results under the Transport Rule trading programs. The recordation deadlines, which are discussed in detail in section XI of this preamble, provide that the Administrator must record existing-unit allowance allocations and auction results by: July 1, 2013 for the applicable control periods in 2014 and 2015; July 1, 2014 for the applicable control periods in 2016 and 2017; July 1, 2015 for the applicable control periods in 2018 and 2019; and July 1, 2016 and July 1 of each year thereafter for the control period in the fourth year after the year of the applicable recordation deadline. In order to provide the Administrator 1 month to review the submissions of allocations and auction results to ensure that the submissions include sufficient information (*e.g.,* the correct identification for each unit involved) to record correctly the submitted allocations and auction results, the state or permitting authority must make these submissions to the Administrator by: June 1, 2013 for the applicable control periods in 2014 and 2015; June 1, 2014 for the applicable control periods in 2016 and 2017; June 1, 2015 for the applicable control periods in 2018 and 2019; and June 1, 2016 and June 1 of each year thereafter for the applicable control period in the fourth year after the year of the applicable submission deadline.

Under the second approach, a state may submit a full SIP adopting a Transport Rule trading program that differs from the comparable Transport Rule FIP trading program only with regard to limited provisions of the FIP trading program. First, the full SIP may include new allocation or auction provisions instead of the Transport Rule FIP allowance allocation provisions other than those concerning the Indian country new unit set-aside. In the state allocation or auction provisions, the state may allocate allowances to Transport Rule units (whether existing or new units) or other entities (such as renewable energy facilities) or may auction allowances. EPA will approve the full SIP only if the state allocation or auction provisions (and any accompanying definitions of terms applying only to terms as used in these provisions) meet certain requirements. Second, the full SIP may substitute the name of the state for the term ''State'' as used in the FIP trading program provisions, provided that EPA determines that the substitutions are not substantive changes. Third, as discussed in more detail below, all references to units in Indian country, as used in the FIP trading program provisions, must be removed, and the full SIP cannot impose any requirements on units in Indian country within the borders of the state and may not include the Indian country set-aside provisions. Other than these allowed changes, all other provisions in the Transport Rule trading program in the full SIP must be the same as those in the Transport Rule FIP trading program with regard to non-Indian country units. For EPA approval, the state allocation provisions must meet the same requirements, as discussed above, that state allocation or auction provisions in an abbreviated SIP must meet.

A Transport Rule trading program adopted by a state in a full SIP, and approved by EPA, under the second approach will be fully integrated with the comparable Transport Rule FIP trading program (*i.e.,* the ''TR NO_X Annual Trading Program'', ''TR NO_X Ozone Season Trading Program'', ''TR SO_2 Group 1 Trading Program'', or ''TR SO_2 Group 2 Trading Program''

[121] EPA is not finalizing opt-in provisions, so the reference to federal-only opt-in allocations in the NODA has been removed.

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respectively) for other states. This will apply whether the comparable Transport Rule FIP program for other states was modified by an abbreviated SIP approved by EPA under the first approach or was not modified by such an abbreviated SIP. The integration of these three types of trading programs will be accomplished primarily through the definitions of the terms, ''TR NO_X Annual allowance'', ''TR NO_X Ozone Season allowance'', ''TR SO_2 Group 1 allowance'', and ''TR SO_2 Group 2 allowance'' in the full SIPs approved by EPA and the TR FIP trading programs (whether or not the programs were modified by abbreviated SIPs). ''TR NO_X Annual allowance'' will be defined in the state and Transport Rule FIP trading programs as including allowances issued under any of the following trading programs: The comparable EPA-approved state Transport Rule trading programs; the comparable Transport Rule FIP trading programs with EPA-approved state allocation and auction provisions; and the Transport Rule FIP trading programs with EPA allocation provisions. Similarly, the definitions in the state and Transport Rule FIP trading programs of ''TR NO_X Ozone Season allowance'', ''TR SO_2 Group 1 allowance'', and ''TR SO_2 Group 2 allowance'' respectively will include allowances issued under all three types of trading programs. As a result, allowances issued in one approved state Transport Rule trading program will be interchangeable with allowances issued in the comparable Transport Rule FIP trading program (whether or not modified by an abbreviated SIP), and all these allowances will be available for use for compliance with the allowance-holding requirements (to cover emissions and to meet assurance provision requirements) in all three types of trading programs.

The integration of state and the proposed Transport Rule FIP trading programs will also be reflected in the definitions of ''TR NO_X Annual Trading Program,'' ''TR NO_X Ozone Season Trading Program'', ''TR SO_2 Group 1 Trading Program'', and ''TR SO_2 Group 2 Trading Program''. Each of these definitions in the state Transport Rule and Transport Rule FIP trading programs will expressly encompass the comparable Transport Rule FIP trading programs (whether or not modified by an abbreviated SIP) and the comparable EPA-approved state full SIP trading program.

The final rule also sets deadlines for the submission of complete abbreviated and full SIPs. These deadlines are based on the first year for which the state wants to allocate or auction allowances, reflect the above-discussed deadlines for the Administrator's recordation of allocations and auction results, and build in a 6-month period for EPA review, provision of notice and opportunity for public comment, and approval of the SIP revisions. This 6-month period is built into the final rule's SIP submission deadlines because that is the period EPA found was needed for reviewing, providing notice and comment for, and approving state trading program provisions in abbreviated and full SIPs under CAIR. As a result, the final rule requires that complete abbreviated and full SIPs must be submitted to the Administrator by: December 1, 2012 in order to govern allowance allocation and auction for control periods in 2014 and 2015; December 1, 2013 in order to govern control periods in 2016 and 2017; December 1, 2014 in order to govern allowance allocation and auction for control periods in 2018 and 2019; and December 1, 2015 and by December 1 of any year thereafter in order to govern allowance allocation and auction for control periods in the fifth year after such submission deadline.

EPA notes that, in cases where a state that has Indian country within its borders submits, and EPA approves, a full SIP, the comparable FIP will not be entirely replaced. In such cases, the FIP will continue to be in place with regard to the Transport Rule trading program provisions that concern units in Indian country, and the full SIP will encompass all other provisions of the trading program. Specifically, to the extent Transport Rule trading program provisions reference and apply to Indian country units (including, for example, references in the applicability provisions and the Indian country new unit set-aside provisions), those provisions, as they apply to Indian country units, will remain in the FIP. The full SIP will include those provisions only as they apply to non-Indian country units.

As a practical matter, this means that the Indian country new unit set-aside provisions, which apply exclusively to Indian country new units, will remain entirely in the FIP. Further, other trading program provisions that reference both non-Indian country units and Indian country units (such as the applicability provisions) will remain in the FIP to the extent of their application to Indian country units and will be included in the full SIP to the extent of their application to non-Indian country units.

However, EPA notes that the assurance provisions in each Transport Rule trading program require calculations using the entire state budget, including any portion of the budget that may be allocated to Indian country new units. Further, EPA notes that currently no new units are planned or anticipated to be located in Indian country. Under these circumstances, EPA will handle the assurance provisions as follows. The full SIP for a state having Indian country will initially include the assurance provisions, as set forth in the FIP, except with removal of any references to sources and units in Indian country. The FIP will initially not include the assurance provisions, which will be fully effective and enforceable under the full SIP. In the event that any new unit is located in Indian country in the state, EPA intends to modify its approval of the full SIP to take back the assurance provisions in order to apply, in the FIP, the assurance provisions to both Indian country and non-Indian country units.

This final rule not only allows a state to choose to submit an abbreviated or a full SIP; it also allows a state to choose to submit either form of SIP to replace any or all of the FIPs in this rule as they apply to a particular state. By promulgating these Transport Rule FIPs, EPA in no way affects the right of a state to submit, for review and approval, a SIP that replaces the federal requirements of the FIP with state requirements that do not involve state participation in the Transport Rule trading programs. In order to replace the FIP in a state, the state's SIP taking an approach other than participation in Transport Rule trading programs must provide adequate provisions to prohibit NO_X and SO_2 emissions that are determined in the Transport Rule to contribute significantly to nonattainment or interfere with maintenance in another state or states. EPA will review such a SIP on a case-by-case basis. The Transport Rule FIPs remain fully in place in each covered state until a state's SIP is submitted and approved by EPA to revise or replace a FIP.

In response to numerous comments urging EPA to allow states to determine allowance allocations as soon as possible, EPA has developed a SIP revision procedure that applies to 2013 allowance allocations only. In developing this procedure, EPA is balancing the desire to allow states the flexibility to tailor allowance allocations to the specific needs and situations in a particular state with the need to provide certainty to source owners and operators by having allowances recorded sufficiently ahead of the control period for which the allocations are made in order to facilitate owners'

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and operators' efforts to optimize their compliance strategies. This final rule allows states to make 2013 allowance allocations through the use of a SIP revision that is narrower in scope than the other SIP revisions states can use to replace the FIPs and/or to make allocation decisions for 2014 and beyond. For 2013 allocations, the scope of the SIP revision is limited to allocations made to units that commence commercial operation before January 1, 2010 and provided in the form of a list of those units and their corresponding allocations for 2013. Additionally, this particular SIP revision may allocate only the portions of the state budgets set forth in Tables X–1 through X–3, *i.e.*, each state budget minus the new unit set-aside and the Indian country new unit set-aside.

In developing this procedure, EPA set deadlines for submissions of the SIP revisions for 2013 allocations and for recordation of the allocations that balanced the need to record allowances sufficiently ahead of the control period with the desire to allow state flexibility for 2013. EPA set deadlines that will allow sufficient time for EPA to review and approve these SIP revisions, taking into account that EPA approval must be final and effective before the 2013 allocations can be recorded and the allowances are available for trading. In order to ensure that EPA review and approval (which must include public notice and opportunity for comment) can be completed in time, the final rule necessarily limits the allowed scope of the SIP revisions for 2013 allocations, as set forth in the requirements discussed below, and thereby limits the issues that must be considered and addressed in the review and approval process. Further, the final rule prescribes the form in which the state allocations for 2013 must be provided to EPA in order to facilitate rapid recordation of the allocations upon their approval.

States, along with their sources, will need to weigh the trade-offs of a relatively short period of recording before the control period for which the allocation is made (about 6 months) with the desire to have state allocations in 2013, when deciding whether to pursue a SIP revision for 2013 allocations. States may choose to submit a SIP revision for one or more of the trading programs. In other words, state allocations for 2013 could apply in one trading program while 2013 FIP allocations apply in another.

States can make 2013 allowance allocations provided the state meets certain requirements.

• By the date 70 days after publication of the final rule in the **Federal Register**, a state must provide notification to EPA if the state intends to submit state allocations for 2013. The notification must be in a format prescribed by the Administrator and submitted electronically.

• By April 1, 2012, the state must submit a SIP revision to EPA that:

Æ Allocates to existing units [122] only, provides a list of the units and their state allocations to EPA electronically and in a format prescribed by EPA, and does not provide for any change in the units and allocations on the list and in any allocation previously determined and recorded by the Administrator;

Æ Allocates a total amount of allowances for 2013 that does not exceed the applicable amount in Tables X–1 through X–3 for each trading program that applies in that particular state; and

Æ Provides for no set-asides and does not alter the new unit set-asides, the Indian country new unit set-asides, and any aspect of the FIP rules other than the existing-unit allocations for 2013.

If EPA does not receive notification from a state by the date 70 days after publication of the final rule in the **Federal Register**, EPA will record FIP allocations for 2012 and 2013 as scheduled (by the date 90 days after publication of the final rule). If EPA receives timely notification from a state, EPA will record FIP allocations for 2012 only and wait to record 2013 allocations. If the state provides a timely (not later than April 1, 2012) SIP revision meeting all the above-described requirements and EPA approves the SIP revision by October 1, 2012, EPA will record state-determined allocations for 2013 by October 1, 2012. Otherwise, EPA will record the EPA-determined allocations for 2013.

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[122] Existing unit means a unit that commenced commercial operation before January 1, 2010.

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Table X-1 Portion of the Annual NO_X Trading Budget Available for State Allocation in 2013

State	Portion of the NO_X Annual Trading Budget Available for State Allocation in 2013
Alabama	71,237
Georgia	60,770
Illinois	44,042
Indiana	106,434
Iowa	37,568
Kansas	30,100
Kentucky	81,683
Maryland	16,300
Michigan	58,989
Minnesota	28,981
Missouri	50,803
Nebraska	24,589
New Jersey	7,121
New York	17,017
North Carolina	47,552
Ohio	90,849
Pennsylvania	117,586
South Carolina	31,848
Tennessee	34,989
Texas	129,587
Virginia	31,580
West Virginia	56,498
Wisconsin	29,730

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Table X-2 Portion of the Ozone-Season NO_X Trading Budget Available for State Allocation in 2013

State	Portion of the Ozone Season NO_X Trading Budget Available for State Allocation in 2013
Alabama	31,111
Arkansas	14,736
Florida	27,268
Georgia	27,385
Illinois	19,511
Indiana	45,470
Kentucky	34,720
Louisiana	13,029
Maryland	7,035
Mississippi	9,957
New Jersey	3,314
New York	8,081
North Carolina	20,838
Ohio	39,262
Pennsylvania	51,157
South Carolina	13,631
Tennessee	14,610
Texas	61,152
Virginia	13,729
West Virginia	24,019

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Table X-3 Portion of the SO_2 Group 1 or Group 2 Trading Budget Available for State Allocation in 2013

State	Portion of the SO_2 Group 1 or Group 2 Trading Budget Available for State Allocation in 2013
Alabama	211,712
Georgia	155,356
Illinois	223,145
Indiana	276,861
Iowa	104,943
Kansas	40,697
Kentucky	218,702
Maryland	29,518
Michigan	224,717
Minnesota	41,141
Missouri	203,317
Nebraska	62,450
New Jersey	5,463
New York	26,778
North Carolina	125,931
Ohio	304,025
Pennsylvania	273,078
South Carolina	86,848
Tennessee	145,187
Texas	231,756
Virginia	67,987
West Virginia	135,942
Wisconsin	75,506

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EPA will work with states that wish to submit full SIPs or abbreviated SIPs to ensure a smooth integration with the relevant Transport Rule trading programs. The Agency intends to provide information and tools to assist states in their rulemaking efforts, including electronic versions of the Transport Rule trading rules and EPA will work with states that wish to submit full SIPs or abbreviated SIPs to ensure a smooth integration with the relevant Transport Rule trading programs. The Agency intends to provide information and tools to assist states in their rulemaking efforts, including electronic versions of the Transport Rule trading rules and other products states feel may be helpful.

States that submit approvable full SIPs or abbreviated SIPs to implement one or all of the Transport Rule trading programs are not required to include an additional technical demonstration relating to elimination of emissions that contribute significantly to nonattainment or contribute to maintenance in downwind areas.

XI. Structure and Key Elements of Transport Rule Air Quality-Assured Trading Program Rules

In order to make the final FIP trading program rules as simple and consistent as possible, EPA designed them so that the final rules (like the proposed rules) for each of the trading programs (*i.e.,* the "TR NO_X Annual Trading Program", "TR NO_X Ozone Season Trading Program", "TR SO_2 Group 1 Trading Program", and "TR SO_2 Group 2 Trading Program") are parallel in structure and contain the same basic elements. For example, the rules for the Transport Rule annual NO_X, ozone-season NO_X, SO_2 Group 1, and SO_2 Group 2 trading programs are located, respectively, in subparts AAAAA (§§ 97.401, *et seq.*), BBBBB (§§ 97.501, *et seq.*), CCCCC (§§ 97.601, *et seq.*), and DDDDD (§§ 97.701, *et seq.*) of Part 97 in Title 40 of the Code of Federal Regulations. Moreover, the order of the specific provisions for each trading program is the same, and the provisions have parallel numbering. The key elements of the final Transport Rule trading program rules are as follows.

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(1) General Provisions

(i) §§ 97.402 and 97.403, 97.502 and 97.503, 97.602 and 97.603, and 97.702 and 97.703—Definitions and Abbreviations

Most of the definitions in the final Transport Rule trading program rules are essentially the same as in the proposed rules and for each of the Transport Rule trading programs (except where necessary to reflect the different pollutants (NO_X and SO_2), control periods (for annual and ozone-season NO_X, and for annual SO_2), and geographic coverage involved in the trading programs). Moreover, many of the definitions in the final rules that are essentially the same as in the proposed rule are also essentially the same as in prior EPA-administered trading programs. However, as discussed in more detail below, some of the definitions in the final rules clarify, or differ from, the definitions in the proposed rule.

As noted, several definitions in the final rules are essentially the same as those both in the proposed rules and in prior EPA-administered trading programs. Examples include the definitions of ''source,'' ''allowance transfer deadline,'' ''owner,'' ''operator'', ''Allowance Management System'' (used instead of the term ''Allowance Tracking System''), and ''continuous emission monitoring system.''

One example of a definition in the final rules that is the same as in the proposed rule, but that clarifies the definition used in prior trading programs is the definition of ''fossil fuel.'' In the final rule, the term ''fossil fuel'' is defined in general as including natural gas, petroleum, coal, or any form of fuel derived from such material, regardless of the purpose for which such material is derived. For example, with regard to consumer products that are made of materials derived from natural gas, petroleum, or coal, are used by consumers, and then are used as fuel, these materials in the consumer products qualify as fossil fuel. The definition in the final rules also includes language establishing a narrower meaning of ''fossil fuel'' that is not generally applicable, but rather is applicable only for purposes of applying the limitation on fossil-fuel use under the solid waste incineration unit exemption (which is discussed elsewhere in this preamble). This latter portion of the ''fossil fuel'' definition makes explicit an interpretation that EPA adopted in CAIR that—solely for purposes of applying the fossil-fuel use limitation in that exemption—the term ''fossil fuel'' is limited to natural gas, petroleum, coal, or any form of fuel derived from such material ''for the purpose of creating useful heat.'' For example, applying this narrower meaning, consumer products made from natural gas, petroleum, or coal are not fossil fuel, for purposes of determining qualification under the fossil-fuel use limitation, because the products (*e.g.*, tires) were derived from natural gas, petroleum, or coal in order to meet certain consumer needs (*e.g.*, to meet transportation needs), not in order to create fuel (*i.e.*, material that would be combusted to produce useful heat).

As noted above, some of definitions in the final rules clarify definitions in the proposed rules. The definitions of ''allowable NO_X emission rate'' and ''allowable SO_2 emission rate'' are clarified by explaining that such a rate is the most stringent state or federal emission rate limitation, expressed in lb/MWhr or, if originally expressed in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit's heat rate in mmBtu/MWhr. This clarification ensures consistency from unit to unit in determining a unit's allowable rate.

By further example, while the proposed rules used the same definition of ''commence commercial operation'' as in prior EPA-administered trading programs, the final rules clarify the definition. Under the definition in the proposed rules, a unit that is physically changed is treated as the same unit. However, the proposed rules were unclear about the treatment of a unit that is replaced and whether moving a unit to a different location or source constitutes a physical change. The definition of ''commence commercial operation'' in the final rules clarifies that a unit that is physically changed (which includes a unit that is replaced) continues to be treated, for purposes of this final rule, as the same unit with the same commence-commercial-operation date. The definition also clarifies that moving a unit to a different location or source is treated the same as a physical change, and so the unit continues to be treated as the same unit. The definition also clarifies that a unit (the replaced unit) that is replaced, whether at the same source or a different source, is treated as the same unit, while the unit (the replacement unit) that replaces the unit is treated as a separate unit with a new commence-commercial-operation date. (The definition of ''commence operation'' is removed in the final rules because they do not use this term.)

By further example, while the proposed rules used the same definition of ''unit'' as in prior EPA-administered trading programs, the final rules clarify the definition. The ''unit'' definition is clarified by expanding it to incorporate explicitly the concepts—set forth in the definition in the final rules of ''commence commercial operation'' and thus already applicable to all units—that a unit that is physically changed, moved to a different location or source, or replaced at the same or a different source continues to be treated as the same unit and that a replacement unit at the same source is treated as a separate unit. EPA believes that it is preferable to provide a comprehensive definition of ''unit'' in one place because the term is used so frequently in the final rules.

By further example, the definition of ''nameplate capacity'' is clarified in the final rules by explaining that it is expressed in MWe rounded to the nearest tenth. This is the same rounding convention that is used in the reporting of nameplate capacity to the Energy Information Administration.

As noted above, some of the definitions in the final rules are similar to those in the proposed rules but have some substantive differences. For example, in the proposed rules, the definitions of ''cogeneration unit'' and ''fossil-fuel-fired'' are similar to those in prior trading programs but with changes to minimize the need for data concerning individual units or combustion devices for periods before 1990. In order to qualify as fossil-fuel-fired, a unit would have to combust any amount of fossil fuel in 1990 or thereafter. In order to qualify as a cogeneration unit, a unit would have to meet certain efficiency and operating standards during the later of: the 12-month period starting when the unit begins producing electricity, or 1990. For a topping-cycle unit, useful power plus one-half of useful thermal energy output of the unit must equal no less than a certain percentage of the total energy input and useful thermal energy must be no less than a certain percentage of total energy output, and, for a bottoming-cycle unit, useful power must be no less than a certain percentage of total energy input. EPA proposed to limit to 1990 or later the historical period for which information on fuel consumption and on cogeneration unit efficiency and operations would be required to apply the ''fossil-fuel-fired'' and ''cogeneration unit'' definitions. This limitation was proposed because EPA was concerned that some owners and operators could have difficulty obtaining pre-1990 information about older units, particularly for units whose ownership has changed over time.

While EPA proposed to use 1990 as the earliest year for which information

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would be required under these definitions, EPA requested comment on whether a more recent year should be used. As discussed elsewhere in this preamble, the final rules use 2005 (about 5 years before this rule's promulgation), rather than 1990, as the reference year. Further, because the language describing the historical time period used (including the reference year), appeared in the proposal both in the ''cogeneration unit'' definition and the provisions concerning cogeneration units in the applicability provisions, the final rules removed any language about the historical time period from the ''cogeneration unit'' definition and revised the language in the applicability provisions to use the 2005 reference year for the requirements for meeting the exemption for cogeneration units from the Transport Rule trading programs. Further, consistent with this use of 2005 as the reference year, the ''fossil-fuel-fired'' definition in the final rule specifically references 2005, rather than 1990, and as discussed elsewhere in this preamble, the final rules also use January 1, 2005 (rather than November 15, 1990) as the reference date throughout the applicability provisions.

With this change in the reference date for the requirement to meet the operating and efficiency standards under the ''cogeneration unit'' definition, a unit would have to meet these standards throughout the later of 2005 or the 12-month period starting when the unit begins producing electricity and continuing thereafter. EPA requested comment on whether these standards should be applied to a calendar year when the unit involved did not combust any fuel, *i.e.,* did not operate at all. As discussed elsewhere in this preamble, the final rules expressly provide that the operating and efficiency standards do not have to be met for a calendar year throughout which a unit did not operate at all.

In addition, under the proposed rules, if a group of cogeneration units operating as an integrated cogeneration system met the efficiency standards, a topping-cycle unit in that system would be deemed to meet those standards. EPA requested comment on whether this provision should also apply to a bottoming-cycle unit. As discussed elsewhere in this preamble, this provision in the final rules is not limited to topping-cycle units.

By further example of definitions in the final rules that have substantive differences from the definitions in the proposed rules, the proposed definitions of ''TR NO_X Annual allowance,'' ''TR NO_X Ozone Season allowance,'' ''TR SO_2 Group 1 allowance,'' ''TR SO_2 Group 1 allowance,'' ''TR NO_X Annual Trading Program,'' ''TR NO_X Ozone Season Trading Program,'' ''TR SO_2 Group 1 Trading Program,'' and ''TR SO_2 Group 1 Trading Program'' are changed in the final rules. Language is added to the definitions in order to reference comparable allowances and trading programs established through SIP revisions submitted by states and approved by the Administrator. As discussed elsewhere in this preamble, the final Transport Rule provides that, if a state submits SIP revisions meeting certain specified requirements, the state or permitting authority (rather than the Administrator) will allocate allowances, and the covered sources in the state will participate—along with covered sources in states remaining subject to the Transport Rule FIPs—in an integrated, region-wide air quality-assured trading program under which both any allowance allocated by the Administrator and any allowance allocated by the state or permitting authority will each authorize one ton of emissions of the relevant pollutant and will be usable by any source for compliance with the requirement to hold allowances covering emissions.

As noted above, the final rules include some definitions that were not used in prior EPA-administered trading programs and that reflect unique provisions of the Transport Rule trading programs. For example, the terms, ''assurance account,'' ''TR NO_X Annual unit,'' ''TR NO_X Ozone Season unit,'' ''TR SO_2 Group 1 unit,'' ''TR SO_2 Group 2 unit,'' ''common designated representative,'' ''common designated representative's assurance level,'' and ''common designated representative's share'' are used and defined in the final rule.

While the proposed rules included definitions for the terms, ''owner's assurance level'' and ''owner's share,'' the final rules replace these terms and instead define the terms, ''common designated representative,'' ''common designated representative's assurance level,'' and ''common designated representative's share.'' This is because, as discussed elsewhere in this preamble, the final rules include assurance provisions similar to those in the proposed rules but that are implemented based on groups of units having a common designated representative, instead of being implemented on an owner-by-owner basis. The definition of ''common designated representative'' in the final rules reflects that the determination of what groups of units and sources in a State have a common designated representative is made based on the identity of units' and sources' designated representatives as of April 1 of the year after the year of the control period when a state triggers the assurance provisions. EPA believes that the use of this reference date will give owners and operators greater flexibility to select common designated representatives after information about total state control period emissions is available and after the allowance transfer deadline when owners and operators may prefer to have a designated representative for their specific source (rather than a common designated representative for a larger group) who is focused on ensuring that sufficient allowances are held in or transferred to the source's account to cover the sources' emissions. EPA notes that the definition of ''common designated representative's share'' is simpler than the definition of ''owner's share'' because implementing the assurance provisions at the designated representative level means it is no longer necessary to address, in the definition, owner- and unit-level issues that may arise when a unit has multiple owners or where two or more units emit through the same stack.

Finally, some definitions are added to the final rules that are not in the proposed rules. For example, because the term, ''business day,'' was used, but not defined, in the proposed rule, its meaning was unclear. Specifically, it was unclear whether a day that was uniquely a state holiday, and not a federal holiday, was a business day for purposes of the federally administered Transport Rule trading programs, *e.g.,* whether the allowance transfer deadline applicable to all sources in all states in a Transport Rule trading program could fall on a day that was a unique state holiday in one or a few states or whether the allowance transfer deadline would be advanced to the next business day for all sources in all states or perhaps only for sources in the state with the state holiday. EPA believes that, for a federally administered trading program covering sources in multiple states, the deadlines should be clear and uniform for all sources, regardless of the state in which the sources are located, and should not be affected by unique state holidays of which owners and operators of sources in other states may not even be aware. Consequently, the ''business day'' definition is added in the final rules and means a day that does not fall on a weekend or a federal holiday.

By further example, a definition for ''natural gas'' was added in the final rules. That definition, as well as the definition for ''coal,'' incorporate the

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corresponding definitions in Part 72 of the Acid Rain Program regulations. The Part 72 definitions are incorporated because they are also used in the Part 75 monitoring, reporting, and recordkeeping provisions, which provisions are already incorporated in the final Transport Rule Trading Program rules. (ii) §§ 97.404 and 97.405, 97.504 and 97.505, 97.604 and 97.605, and 97.704 and 97.705—Applicability and Retired Units

The applicability provisions in the final rules are, except as discussed herein, essentially the same as in the proposed rules and for each of the Transport Rule trading programs. Of course, for each trading program, the definition of ''State'' reflects differences in the specific states whose electric generating units are covered by the respective trading program.

Under the general applicability provisions of the proposed rules, the Transport Rule trading programs would cover fossil-fuel-fired boilers and combustion turbines serving—at any time starting November 15, 1990 or later—an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale, with the exception of certain cogeneration units and solid waste incineration units. As discussed elsewhere in this preamble, the general applicability provisions in the final rules reference January 1, 2005 (about 5 years before this rule's promulgation), rather than November 15, 1990.

Cogeneration unit exemption. Under the final rules (as well as the proposed rules) certain cogeneration units or solid waste incinerators otherwise covered by the general category of covered units are exempt from the FIP requirements. In particular, the final rules include an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify throughout each calendar year ending after the later of 2005 or such 12-month period and that meets the limitation on electricity sales to the grid. In order to qualify as a cogeneration unit (*i.e.,* meet the definition of ''cogeneration unit'') in the final rules, a unit (*i.e.,* a boiler or combustion turbine) must operate as part of a ''cogeneration system,'' which is defined as an integrated group of equipment at a source (including a boiler or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. In addition, in order to qualify, a unit must be a topping-cycle unit or a bottoming cycle unit because units that produce useful thermal energy and useful power through sequential use of energy either produce useful power first (*i.e.,* are topping-cycle units) or produce thermal energy first (*i.e.,* are bottom-cycle units).

Further, in order to qualify as a cogeneration unit, a unit also must meet, on a 12-month or annual basis, the above described efficiency and operating standards. As discussed elsewhere in this preamble, EPA clarifies that the electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWhr.

The final rules also clarify when a unit that meets the requirements for the cogeneration unit exemption and subsequently fails to meet all these requirements loses the exemption and becomes a covered unit. Such a unit loses the exemption starting the earlier of January 1 (or May 1 for the NO_X ozone season trading program) after the first year during which the unit no longer meets the ''cogeneration unit'' definition or January 1 (or May 1) of the first year during which the unit no longer meets the electricity sales limitation.

Solid waste incineration unit exemption. The final rules also include an exemption for a unit that qualifies as a solid waste incineration unit during the later of 2005 or the first 12 months during which the unit first produces electricity, that continues to qualify throughout each calendar year ending after the later of 2005 or such 12-month period, and that meets the limitation on fossil-fuel use. In contrast, the exemption for solid waste incineration units in the proposed rules distinguished between units commencing operation before January 1, 1985 and those commencing operation on or after that date and established somewhat different criteria for these two categories of units. As discussed elsewhere in this preamble, the final rules remove the distinction based on whether a solid waste incineration unit commences operation before January 1, 1985 or on or after January 1, 1985. In order to be exempt, the unit must qualify as a solid waste incineration units during the later of 2005 or the first 12 months during which the unit first produces electricity, must continue to qualify throughout each calendar year ending after the later of 2005 or such 12-month period, and must meet the limitation on fossil-fuel use on a three-year average basis during the first 3 years of operation starting no earlier than 2005 and every 3 years of operation thereafter.

Retired unit exemption. The final rule provisions exempting permanently retired units from most of the requirements of the Transport Rule trading programs are essentially the same as in the proposed rules and for each of the Transport Rule trading programs. The retired unit provisions exempt these units from the requirements for emission monitoring, recordkeeping, and reporting and for holding allowances, as of the allowance transfer deadline, sufficient to cover their emissions. However, the permanently retired units in a state must be included in determining whether owners and operators must surrender allowances, and, if so, how many, to comply with the assurance provisions (which are discussed elsewhere in this preamble) if the state's total covered-unit emissions exceed the state assurance level.

Specifically, a common designated representative must include these units in determining whether his or her share of total emissions of covered units in a state exceed his or her share (generally based on the allowances allocated to the units that he or she represents) of the state trading budget with the variability limit and thus whether the owners and operators of the units that he or she represents have to surrender allowances under the assurance provisions.

(iii) §§ 97.406, 97.506, 97.606, and 97.706—Standard Requirements

The basic requirements applicable to owners and operators of units and sources covered by the Transport Rule trading programs and presented as standard requirements in the final rules are, except as discussed herein, essentially the same as in proposed rules and for each of the Transport Rule trading programs. These basic requirements include: designated representative requirements; emissions monitoring, reporting, and recordkeeping requirements; emissions requirements comprising emissions limitations and assurance provisions; permit requirements; additional recordkeeping and reporting requirements; liability provisions; and provisions describing the effect of the Transport Rule trading program requirements on other CAA provisions.

In particular, the paragraphs addressing emissions requirements for owners and operators describe these requirements in detail and reference

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other sections of the final rules that set forth the procedures for determining compliance with the emissions limitations and assurance provisions. The paragraphs in the final rules concerning compliance with the emissions limitations clarify that owners and operators of a source and each covered unit at the source must hold allowances at least equaling the total control period emissions of all covered units at the source. Further, the paragraphs in the final rules concerning compliance with the assurance provisions differ from those in the proposed rules in that, as discussed elsewhere in this preamble, the final rules implement the assurance provisions based on groups of units with a common designated representative, instead of being implemented on an owner-by-owner basis, as proposed. Under the final rules, the assurance provisions are triggered when total control period emissions by covered units in a state (starting in 2012) exceed the state trading budget plus variability limit. If the assurance provisions are triggered for a state for a control period in a given year, owners' and operators' responsibility for the resulting penalty (*i.e.,* the surrender of allowances for deduction through the transfer of such allowances to the assurance account created by the Administrator for such owners and operators) is determined on a common designated representative basis.

For purposes of implementing the assurance provisions, covered units in a state are in effect grouped by common designated representative (which is defined as an individual (*i.e.,* a natural person) who is the designated representative, as distinguished from the alternate designated representative, for a group of one or more units and sources as of April 1 after the control period for which the state exceeds the state assurance level). The control period emissions of all covered units with a common designated representative are compared with the allowance allocations of such units plus their share of the state variability limit. The owners and operators of the units and sources in each group that has emissions in excess of allocations plus share of variability are subject to the assurance provisions penalty. The owners and operators of the units and sources in each group must transfer to the assurance account created for such owners and operators a total amount of allowances equal to two times such owners' and operators' proportionate share of the state's excess of covered-unit emissions over the state trading budget plus variability.

The group's proportionate share is the percentage resulting from division of the amount of the group's excess of emissions over allocations plus share of variability by the sum of these excess amounts for all groups of units with a common designated representative in the state. The final rule makes it clear that this percentage is not rounded to the nearest whole number, but rather that the calculated amount of allowances resulting from application of this percentage is rounded to the nearest whole number because, in the Transport Rule trading programs, only whole (not fractional) allowances are used. If instead this percentage were rounded before its application, each group's share would be either 100 percent or 0 percent, which would be contrary to the intent of the assurance provisions in both the final rules and the proposed rules.

The provisions addressing the assurance requirements in the final rules reflect this common-designated-representative-based approach. For example, as discussed elsewhere in this preamble, these provisions use the terms, ''common designated representative's share'' and ''common designated representative's assurance level,'' in lieu of the terms, ''owner's share'' and ''owner's assurance level,'' used in the proposed rules. By further example, these final rule provisions refer to both ''common designated representatives'' and ''owners and operators,'' rather than simply ''owners.''

The final rules also explain what vintage year (*i.e.,* allocation year) of allowances can be used in order to comply with the requirement to cover emissions and with the requirements of the assurance provisions. With regard to emissions during a control period in a given year, only allowances allocated for that year or any prior year can be used to cover such emissions. Further, only allowances of the following vintage can be used to meet excess emissions penalties and assurance penalties concerning emissions during a control period in a given year: allowances allocated for that year, any year before that year, or the year immediately after that year. This approach makes the vintage years usable for excess emissions and assurance penalties consistent and helps ensure that allowances will be available to meet these obligations.

The final rules also clarify the standard emission requirements by explaining further what is meant by the provision that an allowance is a limited authorization to emit. The final rules clarify that an allowance provides authorization to emit during the control period in one year and is limited in both its use and its duration. For example, each Transport Rule trading program's final rules state that an allowance provides an emission authorization that can only be used in accordance with the requirements of the respective trading program, such as the requirements specifying what allowances are available for use, and how such allowances must be held or transferred, in order to cover emissions or meet the assurance provisions. By further example, under the final rules, an allowance continues to provide an authorization to emit one ton of the relevant pollutant until the allowance is deducted, *e.g.,* in order to be used for compliance with the requirement to cover emissions or the requirements of the assurance provisions. Moreover, under the final rules, the Administrator has the express authority to terminate or limit the authorization to emit, and thereby change the use and duration of the authorization, described in the final rules, to the extent he or she determines to be necessary or appropriate to implement any provision of the CAA.

The remaining paragraphs in the standard requirements section address permitting, recordkeeping and reporting, liability provisions, and the effect on other CAA provisions. For example, the paragraphs concerning permitting requirements are limited to stating that no title V permit revisions are necessary to account for allowance allocation, holding, deduction, or transfer and that the minor permit modification procedures can be used to add or change general descriptions in the title V permits of the monitoring and reporting approach used by the units covered by each title V permit. These provisions remain essentially the same in the final rules as in the proposed rules.

(iv) §§ 96.407, 97.507, 97.607, and 97.707—Computation of Time

These sections address how to determine the deadlines referenced in the Transport Rule trading program rules and are, except as discussed herein, essentially the same as in the proposed rules and for each of the Transport Rule trading programs. The final rules revise the proposed rule provisions concerning the treatment of the final date in any time period in order to make the provision consistent with the approach discussed above with regard to the new definition of ''business day.'' The revised provision states that, if the final date is not a

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''business day'', then the time period is extended to the next ''business day.''

(v) §§ 97.408, 97.508, 97.608, 97.708 and Part 78—Administrative Appeal Procedures

Under the final Transport Rule, final decisions of the Administrator under the Transport Rule trading programs are appealable to EPA's Environmental Appeals Board under the regulations set forth in Part 78 (40 CFR part 78), which are revised by the final Transport Rule to accommodate such appeals. The provisions in the final Transport Rule concerning appeals are, except as discussed herein, essentially the same as in the proposed Transport Rule. The proposed Transport Rule would add a provision in Part 78 explaining who is an ''interested person'' with regard to a decision, *i.e.,* a person who submitted comments, testimony, or objections as part of the process of making the decision or a person who submitted his or her name to the Administrator to be placed to an interested persons list. The final Transport Rule includes that provision, but with additional language that clarifies the process for submitting a name to be placed on such a list.

(2) Allowance Allocations

Sections 97.410 through 97.412, 97.510 through 97.512, 97.610 through 97.612, and 97.710 through 97.712 set forth: certain information related to allowance allocation and for implementation of the assurance provisions; the timing for allocation of allowances to existing and new units; and the procedures for new unit allocations. In particular, these sections include tables providing, for each state covered by the particular Transport Rule trading program and for each year, the state trading budget (without the variability limit), new unit set-aside, Indian country new unit set-aside (where applicable), and variability limit. These provisions in the final rules differ in several ways, from the proposed rules and are essentially the same for each of the Transport Rule trading programs.

With regard to the tables in the final rules for the state trading budgets (without the variability limits), new unit set-asides, and variability limits, the identity of the specific states involved and the values for each state differ from the tables in the proposed rules. The final rule values reflect the determinations and modeling underlying the final rules and discussed elsewhere in this preamble. Further, as discussed elsewhere in this preamble, the variability limits are only those based on one-year variability and not those proposed to be based on three-year variability, and Indian country set-asides are shown for states with Indian country within their borders.

With regard to existing unit allocations, the final rules provide that these allocations will be set forth in a notice of data availability to be issued by the Administrator. In contrast, the proposed rules stated that existing unit allocations would be set forth in an appendix to the rules for each Transport Rule trading program. EPA believes that including these allocations in a notice of data availability referencing the EPA Web site (rather than publishing them in tables requiring a large number of pages in the **Federal Register** for each Transport Rule trading program) is a more efficient method of making these allocations public, particularly since these allocations may be changed for 2013 and thereafter by states through SIP revisions. In addition, under the final rules the allocations for an existing unit can change if the unit does not operate (*i.e.,* has no heat input) for 2 consecutive years starting in 2012. In that case, the unit continues to receive its existing unit allocation for those years plus only 2 more years. As explained elsewhere in this preamble, this is a modification of the proposed rules, under which a unit that did not operate for 3 consecutive years would continue to receive its existing unit allocation for those years plus 3 more years.

Under the final rule provisions for new units, the Administrator allocates allowances from the new unit set-aside for the state where the respective unit is located and for each year when the unit first becomes eligible for an allocation and each year thereafter. The units eligible for new unit set-aside allocations include units commencing commercial operation on or after January 1, 2010, as well as several other categories of units, such as, for example, existing units that were not initially but then become covered units, existing units whose allocations are lost due to lack of unit operation and that subsequently begin operating again, and units that lost their allocations because they changed location from one state to another. The approach in the final rules differs from the proposed rules, which required that owners and operators initially request allowances from the new unit set-aside when the unit first became eligible for an allocation. As discussed elsewhere in this preamble, under the final rules, EPA identifies which units become eligible and when they become eligible, based on information provided in other submissions (*e.g.,* certificates of representation, monitoring system certifications, and quarterly emissions reports) that such units must make to EPA, and the requirement that owners and operators submit requests for new unit set-aside allocations is removed in the final rules.

The final rules also provide for two rounds of allocations from the new unit set-aside, in contrast with the proposed rules that provided for only one round. In the first round in the final rules (as in the single round in the proposed rules), a unit's new unit set-aside allocation initially equals that unit's emissions—as determined in accordance with §§ 97.430–97.435, 97.530–97.535, 97.630–97.635, and 97.730–97.735 of the final rules and Part 75 (40 CFR part 75)—for the control period (annual or ozone season, depending on the Transport Rule trading program involved) in the preceding year. If the new unit set-aside lacks sufficient allowances to provide this initial allocation for all of the new units, then each new unit is allocated its proportionate share (based on its initial allocation amount) of the allowances in the new unit set-aside. The Administrator issues a notice of data availability informing the public of the specific new unit allocations and provides an opportunity for submission of objections on the grounds that the allocations are not consistent with the requirements of the relevant final rule provisions. A second notice of data availability is subsequently issued in order to make any necessary corrections in the specific new unit allocations. As discussed elsewhere in this preamble, the final rules establish a somewhat different schedule for issuance of these notices of data availability than the proposed rules. In particular, a single set of dates (*i.e.,* for the first notice, June 1 of the year for which the new unit allocations are described in the notice and, for the second notice, August 1 of that year) is established for all of the Transport Rule trading programs. For the reasons discussed elsewhere in this preamble, the final rules provide for a second round of allocations to the extent that any allowances remain in the new unit set-aside after the allocations are made to new units in the first round. (In the proposed rules, remaining allowances were immediately allocated to existing units.) The units eligible for allocations in the second round are new units that commenced commercial operation during the control period for which allocations are being made and during the prior control period. The second round allocation for each such unit initially equals the positive difference (if any) between the unit's

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first round allocation (if any) and the unit's emissions during the control period for which allocations are being made. If the amount of allowances remaining in the new unit set-aside after the first round is insufficient to provide this initial allocation for all of the second round new units, then each such new unit is allocated its proportionate share of the allowances remaining in the new unit set-aside. The Administrator uses notices of data availability (which are issued by December 15 (for the annual trading programs) and September 15 (for the ozone season trading program) of the control period involved and February 15 (for the annual trading programs) and November 15 (for the ozone season trading program) before the allowance transfer deadline for the control period involved, in a manner analogous to the use of such notices in the first round, to inform the public about the identification of the new units in the second round allocations and obtain and consider any objections. The February 15 and November 15 notices also inform the public about the amounts of the second round allocations. If, after both rounds of allocations, any allowances remain in the new unit set-aside, those allowances are allocated to existing units in proportion to such units' allocations.

The final rules also establish a separate Indian country new unit set-aside in each state where Indian country is located (*i.e.,* in Florida, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Nebraska, New York, North Carolina, South Carolina, Texas, and Wisconsin). As discussed elsewhere in this preamble, the Administrator operates the Indian country new unit set-aside in essentially the same manner as state new unit set-aside, except that unallocated allowances remaining in the Indian country new unit set-aside after the two rounds of new unit set-aside allocations are first placed in the new unit set-aside in the state where the Indian country involved is located and then, if still unallocated, are allocated to existing units in the state. As with the state new unit set-aside, EPA will identify the new units qualifying for the Indian country new unit set-aside, calculate the allocations, and issue notices of data availability using the same schedules as notices for the state new unit set-aside.

Under the final rules (like under the proposed rules), if a unit in certain specified categories is allocated allowances that should not have received them, the Administrator applies procedures under which the allocation is not recorded or the amount of the recorded allocations is deducted as an incorrect allocation, with one exception. The exception is where the determination of compliance with the emissions limitation (*i.e.,* requirement to hold allowances covering emissions, as distinguished from the assurance provisions) for the source that includes the unit has already been completed, in which case no action is taken to account for the erroneous allocation for the control period involved.

While this procedure concerning recordation or deduction of allocations is the same as under the proposed rules, the final rules change the description of the circumstances under which this procedure concerning recordation or deduction of allocations is applied. Under both the final rules and the proposed rules, this procedure is applied to a unit (whether an existing unit or a new unit) that receives an allocation but is not actually a covered unit. However, under the final rules, another category of units—*i.e.,* any existing unit that is not located—as of January 1 of the control period for which the allocation is received—in the state from whose trading budget the allocation was made is also subject to this procedure. Although relatively few units are moved from one state to another, EPA believes that it is important to address what happens to such units' allocations, both because each state has a limited trading budget out of which all allocations for a year to existing and new units in that state must be made and because, under the assurance provisions, determinations are made about owners' and operators' surrender of allowances based on, among other things, the allocations for units in a specific state. Because, under the final rules, a unit that is moved from one state to another may lose its existing unit allocation in the first state under the above-described procedure, the final rules also makes such a unit eligible for allocations from the new-unit set-aside of the second state.

Finally, the final rules remove, as no longer necessary, one category of units that the proposed rules included as subject to this procedure. The proposed rules, treated, as existing units, some units that had not yet operated but were projected to operate by January 1, 2012, and so the proposed rules made these units subject to the procedure for not recording or for deducting allocations if they actually were not required to certify their monitoring systems and hold allowances covering emissions starting January 1, 2012. The final rule does not treat projected units as existing units and so this category of units no longer needs to be made subject to this procedure.

(3) Designated Representatives and Alternate Designated Representatives

Sections 97.413 through 97.418, 97.513 through 97.518, 97.613 through 97.618, and 97.713 through 97.718 establish the procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of a source and the units at the source, and for changing the designated representative and alternate designated representative. These sections also describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she can delegate to an agent the authority to make electronic submissions to the Administrator. Except as discussed herein, the provisions in the final rules are essentially the same as in the proposed rules and for each of the Transport Rule trading programs.

The designated representative is the individual (*i.e.,* the natural person) authorized to represent the owners and operators of each covered source and covered unit at the source in matters pertaining to all Transport Rule trading programs to which the source and units were subject. One alternate designated representative (also an individual) can be selected to act on behalf of, and legally bind, the designated representative and thus the owners and operators. Because the actions of the designated representative and alternate legally bind the owners and operators, the designated representative and alternate must submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and is authorized to act on their behalf.

In the final rules (like in the proposed rules), the certificate of representation must contain: Specified identifying information for the covered source (including location) and the covered units at the source and for the designated representative and alternate; the name of every owner and operator of the source and units; and certification language and signatures of the designated representative and alternate. The final rules require an additional piece of identifying information, *i.e.,* whether the unit is located in Indian country. This is necessary in order for the Administrator to implement the above-described Indian country new unit set-aside. All submissions (*e.g.,* monitoring plans, monitoring system certifications, and allowance transfers) under the final rules for a covered

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source or covered unit must be submitted, signed, and certified by the designated representative or alternate, except that electronic submission may be delegated.

In order to change the designated representative or alternate, a new certificate of representation must be received by the Administrator. A new certificate of representation must also be submitted to reflect changes in the owners and operators of the source and units involved. The new certificate must be submitted within 30 days of such changes.

The final rules make explicit an implied requirement of the proposed rules, *i.e.,* that, if a unit is added to a source or is moved from one source to a second source, a certificate of representation needs to be submitted to reflect the change. This requirement is implicit in the proposed rules when a unit is added to a source because the designated representative would not be authorized to make submissions concerning the added unit unless that unit were included on the certificate of representation. Similarly, where a unit is moved to another source, new certificates of representation would need to be submitted in order for the correct designated representative to be authorized to make submissions concerning the moved unit. Moreover, because compliance accounts in the Allowance Management System would cover all units at a given source and would be based on the information in the certificate of representation submitted by the designated representative for the source, when a unit is moved from a source to a second source, the designated representative of the second source would need to submit a certificate of representation removing the moved unit from the list of units.

The final rules explicitly require that a new certificate of representation be submitted to reflect changes (whether caused by the addition or removal of units) in which units are located at a source. In addition, the final rules impose a deadline on the submission requirement of 30 days from the date of the change in the units. This is analogous to the maximum time period between a change in a unit's owner or operator and the deadline for submission of a new certificate of representative reflecting to the change. Long before any actual move of a unit to a new location, owners and operators will need to make decisions about, and plan the implementation of, such a move. Consequently, EPA believes that a 30-day deadline after any move for reflecting the move in the certificate of representation is reasonable. In the event the change involves the addition of a unit that operated before being located at the source, the final Transport Rule also requires that the designated representative provide in the certificate of representation information on the entity from which the unit was obtained, the date on which the unit was obtained, and the date on which the unit became located at the source. In the event of a change involving the removal of a unit, the designated representative must provide in the certificate of representation information on the entity that obtained the unit, the date on which that entity obtained the unit, and the date on which the unit became no longer located at the source. This information will enable the Administrator to determine what actions are necessary to reflect the change in units located at the sources involved. For example, if a covered unit is moved from one source to second source, the Administrator will have the information necessary to determine whether the unit's allocation should be changed to reflect movement of the unit from one state to another.

(4) Allowance Management System

Sections 97.420 through 97.428, 97.520 through 97.528, 97.620 through 97.628, and 97.720 through 97.728 establish the procedures and requirements for using and operating the Allowance Management System (which is the electronic data system through which the Administrator handles allowance allocation, holding, transfer, and deduction), and for determining compliance with the emissions limitations and assurance provisions, in an efficient and transparent manner. The Allowance Management System also provides the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Except as discussed herein, these sections of the final rules are essentially the same as in the proposed rules and for each of the Transport Rule trading programs.

(i) §§ 97.420, 97.520, 97.620, and 97.720—Compliance, Assurance, and General Accounts

Under the final rules, the Allowance Management System contains three types of accounts. One type comprises compliance accounts, one of which the Administrator establishes for each covered source upon receipt of the certificate of representation for the source. A compliance account is the account in which all allowance allocations must be recorded and in which any allowances used by the covered source for compliance with the emission limitations must be held. The designated representative and alternate for the source are also the authorized account representative and alternate for the compliance account.

A second type comprises general accounts, which can be established by any entity upon receipt by the Administrator of an application for a general account. General accounts can be used by any person or group for holding or trading allowances. To open a general account, a person or group must submit an application for a general account, which is similar in many ways to a certificate of representation. The provisions for changing the authorized account representative and alternate, for submitting a superseding application to take account of changes in the persons having an ownership interest with respect to allowances, and for delegating authority to make electronic submissions are analogous to those applicable to comparable matters for designated representatives and alternates.

A third type comprises assurance accounts. The Administrator establishes one assurance account for each group of units having a common designated representative and located in a state where the assurance provisions are triggered by total emissions exceeding the state trading budget plus variability.

(ii) §§ 97.421 Through 97.423, 97.521 Through 97.523, 97.621 Through 97.623, and 97.721 Through 97.723—Recordation of Allowance Allocations and Transfers

Under the final rules, by November 7, 2011, the Administrator must record allowance allocations for existing units, as set forth in a required notice of data availability, for the Transport Rule annual NO_X, ozone-season NO_X, and SO_2 trading programs for 2012 and 2013, unless, as discussed elsewhere in this preamble, a state notifies the Administrator that the state will submit a SIP revision with existing-unit allocations for 2013 by May 1, 2012. If the Administrator approves that SIP revision by October 1, 2012, the Administrator will record the state-determined existing-unit allocations for 2013, and, in the absence of such approval by that date, the Administrator will record the EPA-determined existing-unit allocations for 2013. By July 1, 2013, the Administrator must record existing-unit allowance allocations (whether EPA- or state- determined) for each Transport Rule trading program for 2014 and 2015. By July 1, 2014, the Administrator must

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record existing-unit allowance allocations for each Transport Rule trading program for 2016 and 2017. By July 1, 2015, the Administrator must record existing-unit allowance allocations for each Transport Rule trading program for 2018 and 2019. By July 1, 2016 and July 1 of each year thereafter, the Administrator must record existing-unit allowance allocations for each Transport Rule trading program for the control period in the fourth year after the year of the applicable recordation deadline. By August 1, 2012 and August 1 of each year thereafter, the Administrator must record new-unit allowance allocations for each Transport Rule trading program for that year. These recordation deadlines differ from those in the proposed rules for two reasons. First, as discussed elsewhere in this preamble, EPA is adopting provisions that allow states to submit, and EPA to approve, SIP revisions (abbreviated or full SIPs) under which the state, rather than the Administrator, determines the distribution of allowances under one or more of the Transport Rule trading programs applicable in the state. In selecting allocation recordation deadlines, EPA took into account and balanced certain countervailing factors. On one hand, EPA considered the need to provide a reasonable time for a state to develop, propose, and finalize, and for EPA to review and propose and finalize approval of, the SIP revision and the desirability of providing a reasonable opportunity for state distributions to become effective for a year relatively soon after the 2012 commencement of the Transport Rule trading programs. EPA's experience with prior trading programs has shown that the process for development and submission of SIP revisions by states and approval by EPA in many cases is about 18 months and in some cases even longer. On the other hand, EPA considered the desirability of owners and operators having allocations in their compliance accounts a reasonable time before the year for which the allocations are made (*i.e.,* the vintage year). Having the allocations recorded, to the extent possible, before the vintage year facilitates compliance decisions and use of the allowance market in implementing such decisions. EPA believes that optimally allocations would be recorded at least 3 years in advance of the vintage year.

In balancing these countervailing factors, EPA is adopting an allocation recordation schedule that provides initially for recordation ranging from 6 months to 18 months before the beginning of the control period in the first 2 years (*i.e.,* 2012 and 2013) for which allocations are made and that, as allocations for control periods in subsequent years are recorded, gradually increases the amount of time between recordation and the beginning of the year of the control period involved until allocations are recorded about three and one-half years in advance. With regard to the need to facilitate states' distribution of allowances, this approach gives states multiple opportunities to develop, submit, and obtain EPA approval for SIPs under which the states (rather than EPA) will distribute allowances under the Transport Rule trading programs for control periods relatively early in the programs. Because of time (which has in the past ranged from about 6 months to about 2 years) it may take for a state to develop and submit such a SIP and because of the time (which has in the past been at least 6 months) it will likely take EPA to review and approve such a SIP, EPA believes that 2013 is the first year for which a state can determine allowance distributions and have them recorded some minimal time before the control period involved. With regard to the need to record allowances in advance, this approach achieves recordation at least 6 months in advance and eventually achieves recordation by what EPA believes is an optimal amount of time (greater than 3 years) before the control period for which recorded allowances are issued.

As discussed elsewhere in this preamble, the approach to allowance recordation in the final rules results in following schedule for submission of abbreviated or full SIPs under the final Transport Rule. SIP revisions with existing-unit allocations for 2013 control periods must be submitted to the Administrator by April 1, 2012. Complete abbreviated and full SIPs must be submitted to the Administrator by: December 1, 2012 in order to govern allowance allocation and auction for control periods in 2014 and 2015; December 1, 2013 in order to govern control periods in 2016 and 2017; December 1, 2014 in order to govern allowance allocation and auction for control periods in 2018 and 2019; and December 1, 2015 and by January 1 of any year thereafter in order to govern allowance allocation and auction for control periods in the fifth year after the year of such submission deadline.

The second reason for the differences in the recordation deadlines in the final rules, as compared to the proposed rules, is that, in order to simplify the recordation schedule for owners and operators and EPA, EPA set uniform recordation deadlines for all of the Transport Rule trading programs. EPA believes that these deadlines provide the Agency sufficient time, after receipt of any information necessary to determine allocations (*e.g.,* for new unit set-aside allocations, the emission data from the control period in the prior year), to complete the recordation of allocations and, as discussed above, makes the allocations available to owners and operators before the year for which the allocations are made. EPA notes that these are deadlines and that the Administrator has the discretion, where feasible and appropriate, to record allocations before such deadlines.

Under the final rules (as under the proposed rules), the process for transferring allowances from one account to another is quite simple. A transfer is submitted providing, in a format prescribed by the Administrator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information is submitted to the Administrator and, when the Administrator attempts to record the transfer, the transferor account includes the allowances identified in the form, the Administrator records the transfer by moving the allowances from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

(iii) §§ 97.424, 97.524, 97.624, and 97.724—Compliance With Emissions Limitations

Under the final rules (as under the proposed rules), once a control period has ended (*i.e.,* December 31 for the Transport Rule NO_X and SO_2 annual trading programs and September 30 for the ozone-season NO_X trading program), covered sources have a window of opportunity—until the allowance transfer deadline of midnight on March 1 or December 1 following the control period for the annual and ozone season trading programs respectively—to evaluate their reported emissions and obtain any allowances that they need to cover their emissions during that control period. Each allowance issued in each Transport Rule trading program authorizes emission of one ton of the pollutant involved, and so is usable for compliance in that trading program, for a control period in the year for which the allowance was allocated or a later year. Consequently, each source needs—as of the allowance transfer deadline—to have in its compliance account, or

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properly submit a transfer that moves into its compliance account, enough allowances usable for compliance to authorize the source's total emissions for the control period.

If a source fails to hold sufficient allowances for compliance to cover the emissions, then the owners and operators must provide, for deduction by the Administrator, two allowances allocated for the control period, in the year of when the emissions occurred, any prior year, or the year immediately after the year of the emissions, for every allowance that the owners and operators failed to hold as required to cover emissions. In addition, the owners and operators are subject to discretionary civil penalties for each violation.

(iv) §§ 97.425, 97.525, 97.625, and 97.725—Compliance With Assurance Provisions

Under the final rules (as under the proposed rules), the assurance provisions ensure that each state will eliminate its significant contribution to nonattainment and interference with maintenance that EPA identifies in this action. A requirement that owners and operators surrender allowances under the assurance provisions is triggered only for certain owners and operators of sources and units in a state where the total state covered-unit emissions for a control period exceed the applicable state trading budget with the variability limit. Moreover, the surrender requirement is implemented based on groups of sources and units with a common designated representative. For each group of sources and units with a common designated representative, the owners and operators of such sources and units must surrender allowances only if the units' emissions (referred to as the common designated representative's share of emissions) during the control period involved exceed the units' allocations plus share of the state variability limit (referred to as the common designated representative's share of the state trading budget with variability).

As discussed elsewhere in this preamble, EPA decided to implement the assurance provisions on a common designated representative basis, rather than on an owner basis. The final rules implement in a series of steps the process of determining which states have total covered-unit emissions sufficient to trigger the allowance surrender requirement for a given control period and determining, using the approach based on common designated representatives, which owners and operators are subject to the allowance surrender and whether those owners and operators are in compliance. This common-designated-representative-based process is more streamlined than the owner-based process in the proposed rules.

First, the Administrator performs the calculations necessary to determine whether any state has total covered-unit emissions for a control period greater than the state trading budget with the 1-year variability limit. As discussed elsewhere in this preamble, EPA decided not to use a 3-year variability limit because, among other things, such a limit seems unnecessary to ensuring elimination of significant contribution to nonattainment and interference with maintenance and would make compliance planning extremely difficult for owners and operators. By June 1, 2013 and June 1 of each year thereafter, the Administrator promulgates a notice of data availability of the results of these calculations.

Second, by July 1, for states identified in the June 1 notice of data availability as having emissions exceeding the state trading budget with variability, the designated representative of each new unit in the state that operated during but did not receive an allocation for the year involved must submit a statement to the Administrator with certain information about the unit. This information—*i.e.,* the unit's allowable emission rate for the pollutant involved (NO_X or SO_2) and heat rate—is used to calculate a surrogate allocation for the unit to be used solely for the purposes of determining whether the group of units with a common designated representative that includes the unit had emissions exceeding allocations plus share of the state's variability limit.

Third, the Administrator calculates, for each state identified in the June 1 notice of data availability and for each common designated representative of a group of units (which groups can include one or more units and sources) in the state, the common designated representative's share of emissions, the common designated representative's share of the state trading budget with the variability limit, and the amount (if any) that the groups of owners and operators of units represented by the common designated representative (which groups can include one or more owners and operators) in the state must surrender under the assurance provisions (*i.e.,* the common designated representative's proportionate share of the excess of state emissions over the state trading budget with the variability limit). The Administrator promulgates by August 1 a notice of data availability of the results of these calculations, provides an opportunity for submission of objections, and promulgates by October 1 a second notice of data availability of any necessary adjustments to the calculations. In contrast with the proposed rules, objections may be submitted concerning information in the August 1 notice, whether or not that information was also provided in the June 1 notice. In short, the process of issuing notices is shortened in the final rules by providing one, comprehensive opportunity to submit objections to the June 1 and August 1 notices, rather than two separate opportunities, one for each notice.

Also in contrast with the proposed rules, the deadlines for issuance of notices of data availability for implementation of the assurance provisions are made uniform under the final rules for all of the Transport Rule trading programs. EPA is taking this approach for the same reasons that the deadlines for issuance of notices of data availability for new unit set-aside allocations are made uniform for all of these trading programs.

Fourth, the owners and operators identified in the October 1 notice of data availability as being required to surrender allowances under the assurance provisions must transfer, by November 1, to the assurance account created by the Administrator for such owners and operators the amount of allowances (usable for compliance) that the Administrator determined in the October 1 notice of data availability. Where the October 1 notice indicates that a specified surrender amount is owed by a group of two or more owners and operators, all the group members are liable for the surrender amount, and it is up to the owners and operators in the group to decide who will actually surrender allowances. This is analogous to the situation where a group of two or more owners and operators of covered units at a source is required to hold allowances covering the unit's emissions and therefore the group of owners and operators is liable. *See* 58 FR 3590, 3599 (January 11, 1993) (discussing liability of owners and operators under allowance-holding requirements of the Acid Rain Program).

EPA believes that the approach of making the owners and operators responsible for deciding which of them will actually surrender the necessary allowances under the assurance provisions is reasonable because the identity of who is an owner or operator (particularly who is an owner) of a unit or source and the percentage of an owner's share can change during the year and this information is available to the owners and operators on an ongoing

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basis, and not to EPA unless EPA were to impose new requirements for reporting this information. Further, EPA believes that it is reasonable to leave to private agreements the establishment of procedures for determining when, and under what conditions, specific owners and operators will provide the allowances for surrender. Owners and operators already make these types of determinations with regard to the surrender requirements in meeting the emissions limitations and any excess emission penalties.

As part of implementing the common-designated-representative-based approach of the assurance provisions in the final Transport Rule, the final rules provide that the Administrator (instead of the owners, as in the proposed rules) will create an assurance account for each group of the owners and operators of units and sources with a common designated representative in each state where the assurance provisions are triggered. Because the final rules require owners and operators to transfer surrendered allowances to the appropriate assurance account (rather than requiring the Administrator to deduct from accounts established by the owners), there is no need for the proposed rule provisions concerning identification of which allowances are to be deducted and first-in, first-out deduction in the absence of such identification.

The final rules provide that, in general, the surrender amounts specified in the October 1 notice for owners and operators are final and will not be revised even if the underlying data (*e.g.,* emission data) used in the calculations underlying the October 1 notice are subsequently revised. However, the final rules set forth limited exceptions to this: Where such data are revised as a result of a decision in or settlement of litigation concerning the data on appeal. EPA believes that the limitation on revisions of the surrender amounts specified in the October 1 notice are necessary to provide some certainty to owners and operators and avoid the potential for multiple changes in owners' and operators' required surrender amounts. Because the surrender amount for each group of owners and operators of units and sources with a common designated representative in a state is calculated using emission data from all of the covered units in that state, each change in one or a few units' emission data that might occur after issuance of the October 1 notice could otherwise change the calculated surrender amounts for all or many groups in the state. For the limited exceptions where the final rules provide that the surrender amounts specified in the August 1 notice may be revised, the final rules require the Administrator to set a new surrender deadline for any additional surrender required and to transfer allowances back out of the assurance account involved for any reduced surrender requirement, as appropriate.

Under the final rules (as under the proposed rules), it is not a violation of the CAA for total state covered-unit emissions to exceed the state trading budget with the variability limit or for a group of owners and operators to become subject to the allowance surrender requirement under the assurance provisions. However, the failure of any group of owners and operators to surrender the required amount of allowances in the assurance account created for such owners and operators violates the CAA and is subject to discretionary penalties, with each required allowance that was not surrendered and each day of the control period involved constituting a violation.

(v) §§ 97.426 Through 97.428, 97.526 Through 97.528, 97.626 Through 97.628, and 97.726 Through 97.728—Miscellaneous Provisions

These sections in the final rules (as in the proposed rules) include provisions allowing banking of the allowances issued in the Transport Rule trading programs, *i.e.,* the retention of unused Transport Rule allowances allocated for a given control period for use or trading in a later control period. While this can potentially cause emissions from sources in some states in some control periods to be greater than the allowances allocated for those control periods, the assurance provisions limit such emissions in a way that ensures that each state's significant contribution to nonattainment and interference with maintenance that EPA has identified in this action will be eliminated.

These sections also include provisions stating that the Administrator can, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the Allowance Management System. In addition, the Administrator can review any submission under the Transport Rule trading programs, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information.

(5) Emissions Monitoring, Recordkeeping, and Reporting

Sections 97.430 through 97.435, 97.530 through 97.535, 97.630 through 97.635, and 97.730 through 97.735 establish emissions monitoring, recordkeeping, and reporting requirements for Transport Rule units. These provisions reference the relevant sections of Part 75 (40 CFR part 75), where the specific procedures and requirements for monitoring and reporting NO_X and SO_2 mass emissions are set forth. The provisions in the final rules are virtually the same as the monitoring, recordkeeping, and reporting requirements in the proposed rules and under previous EPA-administered trading programs, *e.g.,* the Acid Rain Program and NO_X Budget and CAIR trading programs. The final rule provisions are also essentially the same for each of the Transport Rule trading programs, except for differences reflecting the different pollutants and control periods involved.

Under the provisions of the final rules and under Part 75, a unit has several options for monitoring and reporting. A unit's options are to use: a CEMS; an excepted monitoring methodology (NO_X mass monitoring for certain peaking units and SO_2 mass monitoring for certain oil- and gas-fired units); low mass emissions monitoring for certain, non-coal-fired, low emitting units; or an alternative monitoring system approved by the Administrator through a petition process. In addition, unit owners and operators may submit, and the Administrator can approve, petitions for alternatives to Transport Rule and Part 75 monitoring, recordkeeping, and reporting requirements.

As discussed elsewhere in this preamble, the final rules and Part 75 specify that each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied and result in a conservative estimate of emissions for the period involved. Further, the final rules and Part 75 require electronic submission, to the Administrator and in a format prescribed by the Administrator, of a quarterly emissions report.

The final rules include revised language in §§ 97.430(b)(3), 97.530(b)(3), 97.630(b)(3), and 97.730(b)(3) that incorporates by reference, and thereby applies to units in the Transport Rule trading programs, clarification that EPA recently adopted in § 75.4(e) of Part 75 (for Acid Rain Program units)

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concerning the requirements for certification, recertification, and diagnostic testing of emission monitoring systems when a unit adds a new stack or new add-on SO_2 or NO_X emission control device. *See* 76 FR 17288, 17298–300 (March 28, 2011). The revised language is adopted for the reasons set forth in the preamble of that Acid Rain Program final rule and in order to continue the approach, in the Transport Rule trading program rules, of adopting monitoring, recordkeeping, and reporting requirements that are generally consistent with those in the Acid Rain Program, which covers many units in the Transport Rule trading programs.

XII. Statutory and Executive Order Reviews

The projected impacts of this final rule as presented throughout the preamble do not reflect minor technical corrections to SO_2 budgets in three states (KY, MI, and NY) made after the impact analyses were conducted. These projections also assumed preliminary variability limits that were smaller than the variability limits finalized in this rule. EPA conducted sensitivity analysis confirming that these differences do not meaningfully alter any of the Agency's findings or conclusions based on the projected cost, benefit, and air quality impacts presented for the final Transport Rule. The results of this sensitivity analysis are presented in Appendix F in the final Transport Rule RIA.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under EO 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities.

Accordingly, EPA submitted this action to the OMB for review under EO 12866 and EO 13563 (76 FR 3821, January 21, 2011) and any changes in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared an analysis of the potential costs and benefits for this action. This analysis is contained in the Regulatory Impact Analysis (RIA) for this action. For more information on the costs and benefits for this rule, please refer to Table VIII.C–3 of this preamble.

When estimating the human health benefits and compliance costs in Table VIII.C–3 of this preamble, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics, and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, EPA adheres to EO 13563, ''Improving Regulation and Regulatory Review,'' (76 FR 3,821, January 21, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a ''regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty'' and that ''identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends.'' EO 13563 also states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' We recognize that the utility sector has compliance obligations related to multiple environmental statutes authorizing regulatory action, including this rule's requirements to reduce interstate transport of harmful ozone and fine particles and their precursors, as well as other rules' requirements to reduce air toxic emissions, to reduce greenhouse gas emissions, to safely manage coal combustion wastes, and to protect aquatic wildlife from water intake procedures. In the wake of promulgating this final rule, EPA recognizes that moving forward the agency needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still securing the fundamentally important environmental and public health benefits that led Congress to enact those authorities in the first place. At the same time, EPA notes that the flexibility inherent in the allowance-trading mechanism included in this rule affords utilities themselves a degree of latitude to determine how best to integrate compliance with the emission reduction requirements of this rule and those of the other rules.

The final rule will also reduce emissions of directly emitted PM and ozone precursors, and estimates of the $PM_{2.5}$-related benefits of these air quality improvements may be found in Tables VIII.C–1 and VIII.C–2 of this preamble. When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated levels above and below a ''bright line'' threshold, EPA includes a ''lowest measured level'' (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered. Approximately 69 percent of the avoided impacts occur at or above an annual mean $PM_{2.5}$ level of 10 $\mu g/m^3$ (the LML of the Laden et al. 2006 study); about 96 percent occur at or above an annual mean $PM_{2.5}$ level of 7.5 $\mu g/m^3$ (the LML of the Pope et al. 2002 study). Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, et al., (2002) to Laden, et al., (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type.

The cost analysis is also subject to uncertainties. Estimating the cost conversion from one process to another is more difficult than estimating the cost of adding control equipment because it is more dependent on plant specific information. More information on the cost uncertainties can be found in the RIA.

A summary of the monetized benefits and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table VIII.C–3 of this preamble. For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

EPA is required to document the information collection burden imposed by the Transport Rule on industry, states, and EPA in an information collection request (ICR). The ICR describes the information collection requirements associated with the Transport Rule and estimates the incremental costs of compliance with all such requirements, such as the requirement for industry to monitor, record, and report emission data to EPA.

The ICR for the final Transport Rule has been submitted for approval by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and the information collection requirements it documents are not enforceable until such approval has been granted. An ICR was also submitted to OMB in support of the proposed Transport Rule; no adverse comment was received by EPA on either the information collection requirements or their associated cost estimates as described in that document.

The costs associated with the information collection requirements of the Transport Rule include start-up and capital costs for units newly affected by an emission trading program, or whose reporting status has changed (*e.g.*, from ozone-season-only to annual reporting), as well as the additional operation and maintenance costs for Transport Rule-affected units already participating in an EPA-administered cap and trade program. More information on the ICR analysis is included in the final Transport Rule docket.

The records and reports generated by these activities will be used by EPA and states to ensure that affected facilities comply with emission limits and other requirements. Such records and reports are also helpful to EPA and states in both identifying affected facilities that may not be in compliance with applicable requirements and in discerning which units and what records or processes should be inspected.

The incremental capital and operating costs associated with the recordkeeping and reporting burden to Transport Rule-affected sources in states participating in the Transport Rule trading programs are approximately $26 million annually in 2010 dollars. The total number of burden hours associated with the recordkeeping and reporting burden to Transport Rule-affected sources in states participating in the Transport Rule trading programs is approximately 185,000 hours annually. These estimates include the annualized cost of installing and operating appropriate SO_2 and NO_X emission monitoring equipment to measure and report the total emissions of these pollutants from affected EGUs (serving generators greater than 25 MW). The burden to state and local air agencies, as documented in the ICR, includes any necessary SIP revisions, performance of monitor certifications, and fulfillment of audit responsibilities. Burden is defined at 5 CFR 1320.3(b).

The amendments do not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance, which is specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information. An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this final rule on small entities, small entity is defined as:

(1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201. For the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours (MWh) or less in the previous fiscal year.

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE XII.C–1—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS code [b]	Examples of potentially regulated entities
Industry	221112	Fossil-fuel-fired electric utility steam generating units.
Federal Government	[c] 221112	Fossil-fuel-fired electric utility steam generating units owned by the federal government.
State/Local Government	2[c]21112	Fossil-fuel-fired electric utility steam generating units owned by municipalities.
Tribal Government	921150	Fossil-fuel-fired electric utility steam generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric generating units only.
[b] North American Industry Classification System.
[c] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. For plants burning fossil fuel as the primary fuel, plant-level boiler and generator capacity, heat input, generation, and emission data were aggregated by owner and then parent company. For cooperatives, investor-owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size.

After considering the economic impacts of this final rule on small entities, EPA certifies that this action will not have a significant economic impact on a substantial number of small entities (No SISNOSE). This certification is based on the economic impact of this final rule to all affected small entities across all industries affected. EPA assessed the potential impact of this action on small entities and found that there are about 660 potentially affected small units (*i.e.*, greater than 25 MW and generating less than 4 million MWh) out of 3,625 existing units in the Transport Rule states. The majority of these EGUs are owned by entities that do not meet the small entity definition. The remaining 271 of the 660 EGUs are owned by 108 potentially affected small entities and are likely to be affected by this rule. EPA estimates that 24 of the 108 identified small entities will have annualized costs greater than 1 percent of their revenues, and the other 84 are projected to incur costs less than 1 percent of revenues. Eleven small entities out of 108—approximately 10 percent—are estimated to have annualized costs greater than 3 percent of their revenues. EPA has lessened the impacts for small entities by excluding all units smaller than 25 MWe. This exclusion, in addition to the exemptions for cogeneration units and solid waste incineration units, eliminates the burden of higher costs for a substantial number of small entities located in the Transport Rule states.

While the total number of small entities has increased compared to the proposal as a result of updated modeling and changes in geographic coverage, the number with compliance costs greater than 1 percent of revenues has fallen, and both the number and percentage of significantly impacted small entities (costs greater than 3 percent of revenues) are lower—now 10 percent compared to 17 percent in the proposal. The share of significantly impacted small entities has fallen because of updated modeling and the change in the allowance allocation methodology (see section VII.D for more information about allowance allocations).

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. In EPA's modeling, most of the cost impacts for these small entities and their associated units are driven by lower electricity generation relative to the base case. Specifically, two small units reduce their generation by significant amounts, driving the bulk of the costs for all small entities. Excluding these two units, one of the main drivers of small entity impacts is higher fuel costs, which the affected units would incur irrespective of whether they had to comply with this rule. In addition, EPA's decision to exclude units smaller than 25 MWe has already significantly reduced the burden on approximately 390 small entities.

For more information on the small entity impacts associated with the final rule, refer to the Regulatory Impact Analysis for this final rule, which can be found in the docket for this rule and on the Web site *http://www.epa.gov/airtransport*.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments, and the private sector. This rule contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, EPA has prepared, under section 202 of the UMRA, a written statement which is summarized later.

Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA held consultations with the governmental entities affected by this rule during the proposal phase. Subsequently, EPA sent a letter to the ten Representative National Organizations to draw their attention to the Transport Rule Notice of Data Availability (NODA) on allowance allocations and other related matters and to invite their comments. During the NODA comment period, EPA participated in informational calls with the Environmental Council of the States (ECOS) and the National Governors Association to provide information about the NODA directly to state and local officials. There were no new concerns raised during these informational calls. In addition, EPA also conducted consultations with federally recognized tribes prior to finalizing this rule and invited them to comment on the allowance allocation NODA. EPA has added a new unit set-aside provision to this final rule specifically for EGUs constructed in Indian country to ensure allowances are available to tribes and tribal sovereignty is respected.

Consistent with section 205, EPA identified and considered a reasonable number of regulatory alternatives. In the proposal, EPA included three remedy options that it considered when developing this final rule: (1) The preferred remedy trading programs, (2) State Budgets/Intrastate Trading, and (3) Direct Controls. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

EPA examined the potential economic impacts on state- and municipality-owned entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet program requirements. Although EPA does not conclude that the requirements of the UMRA apply to the Transport Rule, these impacts have been calculated to provide additional understanding of the nature of potential impacts and additional information.

EPA has determined that this rule contains a federal mandate that may result in expenditures of $100 million or more in 1 year. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments and that development of a small government plan under section 203 of the Act is not required. The costs of compliance will be borne predominately by sources in the private sector although a small number of sources owned by state and local governments may also be impacted. The requirements in this action do not distinguish EGUs based on ownership, either for those units that are included within the scope of the rule or for those units that are exempted by the generating capacity cut-off. Therefore, this rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

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E. Executive Order 13132: Federalism

This final rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The final rule primarily affects private industry, and does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to the final rule.

Although section 6 of Executive Order 13132 does not apply to the final rule, EPA did provide information to state and local officials during development of both the proposal and final rule. EPA sent a letter to the ten Representative National Organizations to draw their attention to the Transport Rule NODA on allowance allocations and other related matters and to invite their comments. Following that letter in early 2011, EPA participated in informational calls with the Environmental Council of the States (ECOS) and the National Governors Association to provide information about the NODA directly to state and local officials. There were no new concerns raised during these informational calls.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13175 (65 FR 67249, November 9, 2000), EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

EPA has concluded that this action may have tribal implications if a new unit covered by the rule is built in Indian country. Additionally, tribes have a vested interest in how this final rule affects their air quality. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. EPA consulted with tribal officials during the process of finalizing this regulation to permit them to have meaningful and timely input into its development.

EPA received comments on the proposed Transport Rule that the Agency did not properly conduct consultation during the proposal phase of the rulemaking process. In response to these comments, EPA sent a letter to all federally-recognized tribes in the country offering consultation. In addition, several commenters also noted that the Agency did not adequately consider opportunities for tribes to enter into any of the trading programs and, in particular, did not consider sovereignty issues when addressing how to distribute allowances to potential new units in Indian country. On January 7, 2011, EPA issued a NODA requesting comment on allocations for new units in Indian country, among other topics.

The Agency held a consultation call with three tribes on January 21, 2011. A follow-up call was held on February 4, 2011 with two of the three original tribes plus 13 additional tribes, as well as representatives from the National Tribal Air Association. In all ten tribes participated in these calls as consultation and six participated as information-sharing. EPA considered the additional input from these consultation and information calls, in conjunction with the public comments, in the development of the final rule. Accordingly, EPA created an Indian country new unit set-aside to specifically address tribes' concerns regarding the protection of tribal sovereignty in the distribution of allowances for new units in Indian country. *See* section VII.D.2 of this preamble for details on the Indian country set-aside for new units constructed in Indian country within states covered by the Transport Rule.

As required by section 7(a) of the Executive Order, EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045 (62 FR 19,885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under EO 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of this planned rule on children, and explain why this planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This action is not subject to Executive Order 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. EPA believes that the emission reductions from the strategies in this rule will further improve air quality and will further improve children's health. Analyses by EPA that show how the emission reductions from the strategies in this rule will further improve air quality and children's health can be found in the RIA for this rule.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy action'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.'' This rule is a significant regulatory action under Executive Order 12866, and this rule is likely to have a significant adverse effect on the supply, distribution, or use of energy. EPA prepared a Statement of Energy Effects for this action as follows.

Under the provisions of this rule, EPA projects that approximately 4.8 GW of additional coal-fired generation may be removed from operation by 2014. In practice, however, the units projected to be uneconomic to maintain may be ''mothballed,'' retired, or kept in service to ensure transmission reliability in certain parts of the grid. These units are predominantly small and infrequently-used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA estimates that average retail electricity prices could increase in the

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contiguous U.S. by about 1.7 percent in 2012 and 0.8 percent in 2014. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, EPA projects limited impacts on coal and gas prices. The average delivered coal price decreases by about 1.4 percent in 2012 and 0.9 percent in 2014 relative to the base case as a result of decreased coal demand and shifts in the type of coal demanded. EPA also projects that the electric power sector-delivered natural gas price will increase by about 0.3 percent over the 2012–2030 timeframe and that natural gas use for electricity generation will increase by approximately 200 billion cubic feet (BCF) by 2014. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, under the Transport Rule, EPA projects that coal production for use by the power sector will increase above 2009 levels by 21 million tons in 2012 and a further 14 million tons in 2014, as opposed to 30 million tons in 2012 and a further 26 million tons in 2014 without the Transport Rule in place. The Transport Rule is not projected to impact production of coal for uses outside the power sector (*e.g.,* export, industrial sources), which represent approximately 6 percent of total coal production in 2009. EPA does not believe that this rule will have any other impacts (*e.g.,* on oil markets) that exceed the significance criteria.

EPA believes that a number of features of the rulemaking serve to reduce its impact on energy supply. First, the trading component of the Transport Rule provides flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner compared to the alternative remedy approaches on which EPA took comment in the proposal, thus minimizing overall costs and the ultimate impact on energy supply. Second, the more stringent budgets for SO_2 are set in two phases, providing adequate time for EGUs to install pollution controls. In addition, both the operational flexibility of trading and the ability to bank allowances for future years helps industry plan for and ensure reliability in the electrical system.

For more details concerning energy impacts, *see* the RIA for the Transport Rule.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards. This rule will require all sources to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), Part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in Part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to Part 75; however, EPA periodically revises the test procedures set forth in Part 75. When EPA revises the test procedures set forth in Part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in Part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority, low-income, and Tribal populations in the United States. During development of this final Transport Rule, EPA considered its impacts on low-income, minority, and tribal communities in several ways and provided multiple opportunities for these communities to meaningfully participate in the rulemaking process. The proposed Transport Rule included an analysis of its effects on these populations; this section describes additional analysis conducted since proposal, EPA's responses to key comments on environmental justice issues raised during the comment period, and the public outreach and comment opportunities for this rule.

A summary of the history, statutory authority, and key components of this final Transport Rule are described in the Executive Summary (section III) of this preamble. That section also summarizes a supplemental notice of proposed rulemaking (SNPR) that EPA is publishing to correct a procedural flaw by providing an opportunity for public comment on issues that arose from new analyses with updated inventories and modeling platforms.

Briefly, this final Transport Rule will reduce emissions of SO_2 and NO_X in 23 eastern and central states in 2012 and 2014 that contribute to annual and/or 24-hour $PM_{2.5}$ nonattainment or interfere with maintenance in downwind states. It will also reduce emissions of ozone-season NO_X in 20 eastern and central states in 2012 and 2014 that contribute to the 1997 ozone nonattainment or interfere with maintenance in downwind states. This rule is replacing an earlier rule (the 2005 Clean Air Interstate Rule (CAIR)) that was first vacated and then remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in 2008.

1. Consideration of Environmental Justice in the Transport Rule Development Process and Response to Comments

The effects of this final Transport Rule on the most highly exposed populations were integral in its development. This rule uses EPA's authority in CAA section 110(a)(2)(d) to reduce sulfur dioxide (SO_2) and (nitrogen oxides) NO_X pollution that significantly contributes to downwind $PM_{2.5}$ and ozone nonattainment or maintenance areas. As a result, the rule will reduce exposures to ozone and $PM_{2.5}$ in the most-contaminated areas (*i.e.,* areas that are not meeting the 1997 ozone and 1997 and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS)). In addition, the rule separately identifies both nonattainment areas and maintenance areas (maintenance areas are those that are projected to meet the NAAQS but that, based on past data, are in danger of

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exceeding the standards in the future). This requirement reduces the likelihood that any areas close to the level of the standard will exceed the current health-based standards in the future.

This final Transport Rule implements these emission reductions using an emission trading mechanism with assurance provisions for power plants. EPA recognizes that many environmental justice communities have voiced concerns in the past about emission trading and the potential for any emission increases in any location. EPA also received several comments on this issue during the comment period for the proposed Transport Rule. As described below, we believe this final rule addresses the concerns raised on this issue during the comment period.

$PM_{2.5}$ and ozone pollution from power plants have both local and regional components: Part of the pollution in a given location—even in locations near emission sources—is due to emissions from nearby sources and part is due to emissions that travel hundreds of miles and mix with emissions from other sources. Therefore, in many instances the exact location of the upwind reductions does not affect the levels of air pollution downwind.

It is important to note that the section of the Clean Air Act providing authority for this rule, section 110(a)(2)(D), unlike some other provisions, does not dictate levels of control for particular facilities. As at least one commenter noted, none of the alternatives put forward by EPA in the proposed rule could have ensured no emission increases at any facility. Under the direct control alternative, the emission rate for each facility would have been limited but each facility could emit more by increasing their power output in order to meet electricity reliability or other goals. Under the intrastate trading option, sources could not trade allowances with sources in other states but individual facilities within each state could have increased their emissions as long as another facility in the state had decreased theirs at some time.

The final Transport Rule allows sources to trade allowances with other sources in the same or different states while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling in each state (the budget plus variability limit). In addition, assurance provisions in the rule outline the allowance surrender penalties for failing to meet the budget plus variability limits; there are additional allowance penalties as well as financial penalties for failing to hold an adequate number of allowances to cover emissions. This approach eliminates emissions in each state that significantly contribute to downwind nonattainment or maintenance areas, while allowing power companies to adjust generation as needed and ensure that the country's electricity needs will continue to be met. EPA maintains that the existence of these assurance provisions, including the penalties imposed when triggered, will ensure that state emissions will stay below the level of the budget plus variability limit.

In addition, all sources must hold enough allowances to cover their emissions. Therefore, if a source emits more than its allocation in a given year, either another source must have used less than its allocation and be willing to sell some of its excess allowances, or the source itself had emitted less than its allocation in one or more previous years (*i.e.,* banked allowances for future use).

In summary, the final remedy addresses commenter concerns about localized hot spots and reduces ambient concentrations of pollution where they are most needed by sensitive and vulnerable populations by: Considering the science of ozone and $PM_{2.5}$ transport to set strict state budgets to eliminate significant contributions to ozone and $PM_{2.5}$ nonattainment and maintenance (*i.e.,* the most polluted) areas; implementing air quality-assured trading; requiring any emissions above the level of the allocations to be offset by emission decreases; and imposing strict penalties for sources that contribute to a state's exceedance of its budget plus variability limit. In addition, it is important to note that nothing in this final rule allows sources to violate their title V permit or any other federal, state, or local emissions or air quality requirements.

EPA received comments from several tribal commenters regarding the lack of allocations in the proposal to new units in Indian Country. EPA responded to these comments by changing the allocation approach in the final rule to create Indian country new unit set-asides. In order to protect tribal sovereignty, these set-asides will be managed and distributed by the federal government regardless of whether the Transport Rule in the adjoining or surrounding state is implemented through a FIP or SIP. While there are no existing power plants in Indian country covered by this Transport Rule, the Indian country set-asides will ensure that any future new units built in Indian country will be able to get the necessary allowances. A full discussion of the Indian country new unit set-asides can be found in section VII.D.2.

EPA also received several comments during the comment period from individuals and groups requesting additional emission reductions to further protect sensitive and vulnerable communities. While EPA has adjusted the emission requirements somewhat in the final rule to accommodate revised data and updated modeling results, we are finalizing emission reductions very similar to the level in the proposal. This is because EPA believes that the emission reductions required by this final rule are appropriate to meet the statutory requirements of CAA section 110(a)(2)(d) and respond to the concerns raised by the Court's opinion in *North Carolina* that remanded CAIR to the Agency in 2008.

In addition, it is important to note that CAA section 110(a)(2)(d), which addresses transport of criteria pollutants between states, is only one of many provisions of the CAA that provide EPA, states, and local governments with authorities to reduce exposure to ozone and $PM_{2.5}$ in communities. These legal authorities work together to reduce exposure to these pollutants in communities, including for minority, low-income, and tribal populations, and provide substantial health benefits to both the general public and sensitive sub-populations.

For example, the recently-proposed Mercury and Air Toxics Standards (MATS) would also result in significant reductions in SO_2 emissions and provide significant health and environmental benefits nationwide. This and other actions described in section III will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from environmental justice communities, among many others. EPA will continue to provide multiple opportunities for comment on these actions, similar to the opportunities provided during the comment process for this rule, detailed at the end of this section. We encourage environmental justice communities to review and comment on these actions.

2. Potential Environmental and Public Health Impacts Among Populations Susceptible or Vulnerable to Air Pollution

EPA expects that this final rule will provide significant health and environmental benefits to, among others, people with asthma, people with heart disease, and people living in ozone or $PM_{2.5}$ nonattainment areas. EPA's analysis of the effects of this rule, including information on air quality changes and the resulting health benefits, is presented both in section

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VIII of this preamble and in the Regulatory Impact Analysis (RIA) for this rule. These documents can be accessed through the rule docket No. EPA–HQ–OAR–2009–0491 and from the main EPA webpage for the rule at *http://www.epa.gov/airtransport.*

EPA considered several aspects of the effects of the Transport Rule on minority, low-income, and tribal populations. These included: amount of emission reductions and where they take place (including any potential for areas of increased emissions); the changes in ambient concentrations across the affected area; the estimated health benefits; and how the estimated health benefits are distributed among different populations, including those susceptible and vulnerable to air pollution health impacts.

a. Emission Reductions

EPA's emission modeling data indicate that implementation of the Transport Rule will substantially reduce SO_2 emissions from electric generating units (EGUs). As noted in section III, emissions in states covered by the Transport Rule will decrease by 6.4 million tons (73 percent) in 2014 compared to 2005 (the year the Clean Air Interstate Rule was finalized). Emissions are also projected to decrease when compared to the base case (the base case estimates emissions in 2014 in the absence of this rule or the Clean Air Interstate Rule it is replacing). EPA estimates that SO_2 emissions in 2014 in covered states will be 3.9 million tons lower (62 percent lower) compared to the base case.

EPA also assessed emission changes in states not covered by the Transport Rule. Emissions in the states not covered by the Transport Rule are also projected to decrease substantially compared to 2005 levels; in 2014 SO_2 emissions are projected to be approximately 430,000 tons lower (30 percent lower) than in 2005.

As described in section VI.C, EPA's modeling does project that some states not covered by any of the fine particle control programs in the final Transport Rule may experience increases of SO_2 emissions greater than 5,000 tons compared to the base case. These states are Arkansas, Colorado, Louisiana, Montana, and Wyoming. These emission increases are the result of forecasted changes in operation of power plant units outside of the Transport Rule states due to the interconnected nature of the utility grid (*i.e.,* shifts in generation of electricity to sources outside the Transport Rule states) or influence of the rule on the market for lower sulfur coal. For example, EPA projects that the rule will raise demand for lower sulfur coal in the states covered by the Transport Rule for $PM_{2.5}$ (thereby raising its price), which may lead sources in states not covered for $PM_{2.5}$ to choose higher-sulfur coals that increase SO_2 emissions in those states.

EPA is not requiring SO_2 emission reductions in these states under this rule because our modeling indicates none of these states' contributions would increase enough to cause them to meet or exceed the thresholds described in section V.D for either of the $PM_{2.5}$ standards. EPA's authority under CAA section 110(a)(2)(d) is limited to addressing this significant contribution to nonattainment and interference with maintenance. However, as noted above, EPA has recently proposed the Mercury and Air Toxics Standards that will apply nationwide and result in substantial additional SO_2 emission reductions, including in states not covered by the Transport Rule.

EPA's emission modeling data indicates that ozone-season NO_X emissions from EGUs in states covered by the Transport Rule will be approximately 340,000 tons lower (36 percent lower) in 2014 than they were in 2005. Emissions in states not covered by the Transport Rule are also expected to decrease somewhat (approximately 82,000 tons or 25 percent). EPA's modeling does project that two states (California and Pennsylvania) may experience increases of NO_X emissions greater than 5,000 tons in 2014 compared to 2005 levels. California is not covered by the Transport Rule; in Pennsylvania, 2005 was an unusually low-emitting year and sources are projected to increase their heat input slightly (usually meaning they are generating more power) after the rule takes effect.

EPA also assessed the expected changes in seasonal NO_X emissions with implementation of the Transport Rule compared to the base case (*i.e.,* without the rule) in 2014. The modeling indicates ozone-season NO_X emissions from EGUs in both covered states and non-Transport Rule states under this rule will be lower than they would have been in 2014 in the base case. Ozone-season NO_X emissions in covered states are projected to decrease by approximately 74,000 tons (11 percent); ozone-season NO_X emissions in non-Transport Rule states are projected to decrease by approximately 10,000 tons (4 percent). Both California and Pennsylvania are projected to have lower NO_X emissions in 2014 under the Transport Rule as compared to the base case. In addition, EPA anticipates that additional upcoming actions, including likely additional interstate transport reductions to help states attain the upcoming new ozone NAAQS, will result in significant additional NO_X reductions in the future.

b. Air Quality Improvements

EPA assessed the air quality metrics (called ''design values'') for each NAAQS addressed in this rule: 24-hour $PM_{2.5}$, annual $PM_{2.5}$, and ozone. We then compared these metrics for the final rule to the same metrics in the recent past (2003–2007 average ambient air quality) and for the 2014 base case to assess improvements in air quality.

EPA's modeling indicates that there will be significant improvements in air quality as measured by the 24-hour $PM_{2.5}$ standard. Throughout much of the eastern half of the U.S., 24-hour $PM_{2.5}$ design values are projected to improve more than 10 $\mu g/m^3$ compared to the 2003–2007 average levels. In addition, compared to the 2014 base case levels, we project the Transport Rule will result in improvements of 8–10 $\mu g/m^3$ in a broad swath of states stretching from far southwestern New York through Pennsylvania, Ohio, West Virginia, Maryland, Indiana, southern Illinois, eastern Missouri, eastern Arkansas, Kentucky, Tennessee, northern Alabama, and northern Mississippi. Isolated areas of Virginia and northern New Jersey are also expected to see this level of improvement. Improvements of 2–6 $\mu g/m^3$ are projected in surrounding states stretching from New England and New York to Minnesota, Iowa, the far eastern edge of Nebraska, Missouri, eastern Kansas, Oklahoma, Texas, the Gulf of Mexico states, and the states bordering the Atlantic Ocean from Florida to New Hampshire.

EPA modeling indicates that air quality as measured by the annual $PM_{2.5}$ design value will also improve. Improvements range from 2 to over 4 $\mu g/m^3$ compared to the 2003–2007 average levels throughout the eastern half of the U.S. Annual $PM_{2.5}$ air quality with the Transport Rule is also projected to improve compared to the 2014 base case levels. The largest improvements of up to 4 $\mu g/m^3$ are projected to occur in northern West Virginia and a small area in northwestern Tennessee. Improvements of up to 3 $\mu g/m^3$ are projected for portions of the Ohio River valley areas of southwestern Pennsylvania, Ohio, West Virginia, Kentucky, central Tennessee, and southern Indiana. Improvements of up to 2 $\mu g/m^3$ are projected to take place in a ring of surrounding states including all or most of New York, Michigan, Indiana,

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Illinois, Missouri, Arkansas, the far eastern edge of Oklahoma, the northeastern edge of Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Delaware, Pennsylvania, and New Jersey. Smaller improvements are projected in New England, Wisconsin, the Plains states, southeastern New Mexico, and Florida.

EPA modeling indicates that ozone air quality will improve greatly (10–12 ppb or more) across much of the eastern U.S. between the average levels seen in 2003–2007 and implementation of the Transport Rule. Most of the improvements take place in the base case; that is, they are the result of federal and state programs other than the Transport Rule. However, ozone air quality is projected to improve somewhat as a direct result of the Transport Rule. Improvements in ozone design values compared to the base case of more than 1 ppb are projected for portions of Florida, eastern Oklahoma, and areas along the upper reaches of the Ohio River. In addition, improvements in ozone design values of up to 1 ppb are projected over a wide area across the eastern U.S. from New England to Texas and north to Minnesota. Improvements are also projected in north-central Colorado.

EPA's modeling does indicate small increases in annual $PM_{2.5}$ air quality design values in the final rule compared to the 2014 base case in two counties outside of the Transport Rule states: one county in northern Colorado and one county in eastern Montana. As noted above in the section on emissions, these increases are likely the result of forecasted changes in electricity generation due to the interconnected nature of both the utility grid and the national low-sulfur coal market. It should be noted that 2003–2007 average air quality levels in these counties are well below the level of the NAAQS. In addition, other actions, including federal rules such as the recently proposed Mercury and Air Toxics Standards, state, or local actions may also improve air quality in these areas over the next few years.

As described in section VIII.B, EPA anticipates that this final rule will reduce, but not eliminate, the number of nonattainment and maintenance areas for the 1997 ozone and $PM_{2.5}$ and 2006 $PM_{2.5}$ NAAQS. As noted above, ozone and $PM_{2.5}$ concentrations are the result of both local emissions and long-range transport of pollution. Even when the significant contributions of upwind states are fully eliminated, additional emission reductions within the nonattainment area and/or the downwind state will be needed for some areas to attain and maintain the NAAQS.

c. Estimated Health Benefits

This rule reduces concentrations of $PM_{2.5}$ and ozone pollution. Exposure to these pollutants can cause, or contribute to, adverse health effects that affect many minority, low-income, and tribal individuals and communities. $PM_{2.5}$ and ozone are particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure to these pollutants can cause premature death and trigger heart attacks, asthma attacks in those with asthma, chronic and acute bronchitis, emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. High rates of heart disease (*e.g.,* high blood pressure) [123] and asthma [124] exist in many environmental justice communities, making these populations more susceptible to air pollution health impacts. In addition, many individuals in these communities lack access to high quality health care to treat these illnesses.[125]

We estimate that in 2014 the PM-related annual benefits of the final rule include approximately 13,000 to 34,000 fewer premature mortalities, 8,700 fewer cases of chronic bronchitis, 15,000 fewer non-fatal heart attacks, 8,500 fewer hospitalizations (for respiratory and cardiovascular disease combined), 10 million fewer days of restricted activity due to respiratory illness, and approximately 1.7 million fewer lost work days. We also estimate substantial health improvements for children in the form of fewer cases of upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include (in addition to the PM-related benefits above) between 27–120 fewer premature mortalities, 240 fewer hospital admissions for respiratory illnesses in children and older adults, 86 fewer emergency room admissions for asthma, 160,000 fewer days with restricted activity levels, and 51,000 fewer "school absence" days when children are absent from school due to illnesses. When adding the PM and ozone-related mortalities together, we find that the final rule will yield between 13,000 and 34,000 fewer premature mortalities.

It should be noted that, as discussed in the RIA, there are other benefits to the emission reductions discussed here, including many other health benefits beyond reducing the risk of premature mortality. Additional benefits of reducing emissions of SO_2 include improved visibility, reduced acidification of lakes and streams, and reduced mercury methylation in contaminated waters; additional benefits of NO_X reductions include improved visibility, reduced acidification of lakes and streams, and reduced coastal eutrophication.

d. Distribution of Health Benefits Among Different Populations

EPA also estimated the $PM_{2.5}$ mortality risks according to race, income, and educational attainment before and after implementation of this Transport Rule. We used premature mortality for this analysis for several reasons: It is the most serious health effect of exposure to $PM_{2.5}$, and EPA has access to nationwide incidence and demographic data at an appropriate scale to conduct this type of analysis. EPA included educational attainment in this assessment because research on the effects of $PM_{2.5}$ has found that educational attainment is inversely related to the risk of all-cause mortality. That is, populations with lower levels of education (in particular, less than grade 12) experience higher rates of $PM_{2.5}$ mortality. Krewski and colleagues [126] note in their analysis of this relationship that the level of education attainment is likely to be a surrogate for the effects of complex socioeconomic processes (including factors such as race and income) on mortality.

In the first step of the analysis, we estimated baseline (2005) $PM_{2.5}$ mortality risk by race (White, Black, Asian, Native American) among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk. We

[123] Neighborhood of Residence and Incidence of Coronary Heart Disease Ana V. Diez Roux, M.D., PhD *et al.* N Engl J Med 2001; 345:99–106; July 12, 2001.

[124] Centers for Disease Control and Prevention. 2007 National Health 11. Interview Survey Data. Table 4–1. Current Asthma Prevalence Percents by Age, United States: National Health Interview Survey, 2007. Atlanta, GA: U.S. Department of Health and Human Services, CDC, 2010. Accessed June 1, 2010.

[125] R. Nelson, Eds. National Institute of Medicine, 2003.

[126] Krewski D, Jerrett M, Burnett RT, Ma R, Hughes E, Shi Y, Turner C, Pope CA, Thurston G, Calle EE, Thunt MJ. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. HEI Research Report, 140, 2009; Health Effects Institute, Boston, MA.

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also estimated baseline $PM_{2.5}$ mortality risk by race among people living in the counties with both the highest (top 5 percent) poverty rate and the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. And, we estimated the baseline (2005) $PM_{2.5}$ mortality risk by educational attainment for people living in the highest $PM_{2.5}$ mortality risk counties. In the second step, we estimated the changes in risk for different races among the people living in these "high-risk" and "high risk and high-poverty" counties resulting from implementation of other existing rules in 2014 and from implementation of just the Transport Rule in 2014. Finally, in the third step, we compared the effects of the Transport Rule by race in the high-risk and high risk/high-poverty counties with the effects on people (by race) living in all other counties.

In 2005, people living in the highest-risk counties and in the high risk/high poverty counties had substantially greater risks of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was true regardless of race: The difference among races in both groups of counties was very small and dwarfed by the large difference between the two groups of counties for all races. For educational attainment, in contrast, our analysis found that people with less than high school education had significantly greater risks from $PM_{2.5}$ mortality than people with a greater than high school education. This was especially true for people living in the highest-risk counties, but also held true for people living in all other counties. In summary, in 2005, having less than a high school or high school education, living in one of the poorest counties, and living in a high air pollution risk county are associated with higher $PM_{2.5}$ mortality risk; race is not.

Our analysis of the effects of the Transport Rule on this underlying exposure pattern finds that the rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2014 pre-rule (*i.e.,* base case) levels. No group will experience any increases in $PM_{2.5}$ related deaths as a result of implementing the Transport Rule.

The analysis indicates that the populations with the largest improvement (*i.e.,* largest decline) in $PM_{2.5}$ mortality risk as a result of the Transport Rule in 2014 (compared to the base case in 2014) are people living in the highest-risk counties. Among these counties, the largest improvements are for people with less than high school or high school education. These reductions in risk within the highest-risk counties, as well as the reductions in risk within the other 95 percent of counties, are distributed among populations of different races fairly evenly. Therefore, there is no indication that people of particular race receive a greater benefit (or smaller benefit) than others.

The analysis indicates that people living in the high risk/high poverty counties will experience larger improvements in risk from the Transport Rule compared to their counterparts in the other counties. This result suggests that the Transport Rule is providing the greatest risk reduction improvements among counties containing the poorest, and highest risk, populations. There is also little difference in the improvement in risk among races; in other words, people in the high risk/high poverty counties experience the same improvement in risk regardless of race.

The analysis also indicates that this rule, in conjunction with the implementation of existing or proposed rules (*e.g.,* the proposed Mercury and Air Toxics Standards), will reduce the disparity in risk between the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, implementation of this Transport Rule and other rules will, together, reduce risks in the poorest and highest risk counties to the approximate level of risk for the rest of the counties before implementation. This analysis is presented in more detail in the RIA for this rule which is available in the rule docket No. EPA–HQ–OAR–2009–0491 and from the main EPA webpage for the rule at *http://www.epa.gov/airtransport.*

3. Meaningful Public Participation

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, EPA developed a communication and outreach strategy to ensure that interested communities had access to the proposed Transport Rule, were aware of its content, and had an opportunity to comment during the comment period. These efforts are summarized below.

As EPA began considering approaches to address the court remand of the 2005 Clean Air Interstate Rule, long before the rule was proposed, the agency also began gathering input from a large range of stakeholders. In the spring of 2009, EPA held a series of listening sessions to gather information and perspectives from stakeholders prior to the formal start of the rulemaking process. These stakeholders included a number of environmental groups who requested that EPA consider several potential environmental justice issues during development of this rule. In addition, many environmental justice organizations were represented at a November 2009 EPA-Health and Human Services White House Stakeholder Briefing titled, "The Public Health Benefits of Energy Reform" in which EPA discussed our intention to propose this rule in the spring of 2010 and participants had the opportunity to respond. Finally, EPA notified Indian Tribes of our intent to propose this rule in the fall of 2009 during a regularly scheduled meeting to update the National Tribal Air Association members of upcoming EPA policies and regulations and to receive input from them on the effects of these efforts in Indian country. These were not opportunities for stakeholders to comment on the specifics of the proposal, as they took place prior to its development, but they provided valuable information that EPA used in developing the proposal.

Just after the rule was proposed in July 2010, EPA presented a summary of information related to the proposed Transport Rule at the National Environmental Justice Advisory Council (NEJAC) meeting in Washington, DC, and responded to questions from NEJAC members regarding the proposed rule. EPA also solicited suggestions for how to engage environmental justice communities during the rule comment period.

During the public comment period, EPA held public hearings in Chicago, Philadelphia, and Atlanta. Each hearing was advertised by EPA through a variety of products targeted to general audiences (*e.g.,* fact sheets, press release, slide presentation, etc.); on EPA's environmental justice listserve; and by non-profit organizations (*e.g.,* American Lung Association). The public hearings were held in public buildings (*i.e.,* no formal identification required to enter or to speak) and were open for 11 hours (9 a.m.–8 p.m.) to accommodate commenters with various work schedules. All three hearings were well-attended by members of the general public. During hearing breaks, EPA staff spent time talking with individuals, including those representing environmental justice organizations or communities, to understand their perspectives in greater detail. As noted above, several commenters at each hearing made comments related to the need to protect communities living near power plants and the most vulnerable

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individuals. Some of these commenters specifically mentioned environmental justice; others mentioned issues often of concern to environmental justice communities, such as hot spots, interest in additional emission reductions and greater environmental protection, and concern over the effects of the rule on the most sensitive and vulnerable populations.

In September 2010, during the comment period, EPA held a webinar for EJ communities on the proposed Transport Rule. A presentation tailored for an audience of environmental justice, community, and tribal representatives was specifically designed for this webinar. It was sent to registered participants beforehand and put on the Transport Rule webpage, where it remains posted. The presentation included both information on the context of the rule, plain language information describing the rule itself, and directions on how to comment on the rule.

EPA staff made a short presentation and answered questions about the Transport Rule on a standing bi-monthly community conference call targeted to environmental justice and tribal representatives and organizations. In addition, at the fall 2010 NEJAC meeting in Kansas City, Missouri, EPA provided details of the proposed Transport Rule as part of a larger discussion of a sector-based approach to utility regulation.

Regarding tribal consultation, EPA sent letters to all 565 federally-recognized Tribes in the country offering consultation on the proposed Transport Rule. In addition, the January 7 NODA on allowance allocation methodologies specifically requested comment on allocating allowances to new units in Indian Country. EPA held two consultation and information-sharing calls with 16 interested Tribes in late January and early February 2011. Tribes participating on these consultation and information calls provided comments on the proposed rule and the allowance allocation NODA. As noted above, this additional input from the consultation process was taken into account in the development of the final rule. *See* Section XII.F for more information on tribal consultation.

4. Summary

EPA believes that the vast majority of communities and individuals in areas covered by this rule, including numerous low-income, minority, and tribal individuals and communities in both rural areas and inner cities in the eastern and central U.S., will see significant improvements in air quality and resulting improvements in health. EPA's assessment of the effects of the proposed and final Transport Rules on these communities included: (a) The structure of the rule and responses to comments received on issues specific to these communities; (b) expected SO_2 and NO_X emission reductions; (c) expected $PM_{2.5}$ and ozone air quality improvements; (d) expected health benefits, including asthma and other health effects of particular concern for environmental justice communities; and (e) a quantitative assessment of the expected socioeconomic distribution of a key health benefit (reduction in premature mortality). All of these analyses indicate large health and environmental benefits for these communities; none shows evidence of adverse effects. As a result, EPA concludes that we do not expect disproportionately high and adverse human health or environmental effects on minority, low-income, or tribal populations in the United States as a result of implementing this final Transport Rule.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective October 7, 2011.

L. Judicial Review

Petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by October 7, 2011. Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

Any final action related to the Transport Rule is ''nationally applicable'' within the meaning of section 307(b)(1). Through this rule, EPA interprets section 110 of the CAA, a provision which has nationwide applicability. In addition, the Transport Rule applies to 27 States. The Transport Rule is also based on a common core of factual findings and analyses concerning the transport of pollutants between the different states subject to it. For these reasons, the Administrator also is determining that any final action regarding the Transport Rule is of nationwide scope and effect for purposes of section 307(b)(1). Thus, pursuant to section 307(b) any petitions for review of final actions regarding the Transport Rule must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

Filing a petition for reconsideration of this action does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed and shall not postpone the effectiveness of such rule or action. In addition, pursuant to CAA section 307(b)(2) this action may not be challenged later in proceedings to enforce its requirements.

In addition, this action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, to ''the promulgation or revision of an implementation plan by the Administrator under CAA section 110(c)'' (42 U.S.C. 7407(d)(1)(B)). The Agency has complied with procedural requirements of CAA section 307(d) during the course of this rulemaking.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 52

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen

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oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 72

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 97

Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: July 6, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, parts 51, 52, 72, 78, and 97 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 51—[AMENDED]

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

§ 51.121 [Amended]

■ 2. In § 51.121 paragraph (r)(2) is amended by removing the words "§ 51.123(bb)" and adding, in their place, the words "§ 51.123(bb) with regard to an ozone season that occurs before January 1, 2012".

■ 3. Section 51.123 is amended by adding a new paragraph (ff) to read as follows:

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

* * * * *

(ff) Notwithstanding any provisions of paragraphs (a) through (ee) of this section, subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS and the 8-hour ozone NAAQS meeting the requirements of paragraphs (b) through (ee) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, or in any emissions trading program provisions in a State's SIP approved under this section;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

■ 4. Section 51.124 is amended by adding a new paragraph (s) to read as follows:

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

* * * * *

(s) Notwithstanding any provisions of paragraphs (a) through (r) of this section, subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS meeting the requirements of paragraphs (b) through (r) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, or in any emissions trading program in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

§ 51.125 [Reserved]

■ 5. Section 51.125 is removed and reserved.

PART 52—[AMENDED]

■ 6. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—General Provisions

■ 7. Section 52.35 is amended by adding a new paragraph (f) to read as follows:

§ 52.35 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of nitrogen oxides?

* * * * *

(f) Notwithstanding any provisions of paragraphs (a) through (d) of this section, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) through (d) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

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(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods.

■ 8. Section 52.36 is amended by adding a new paragraph (e) to read as follows:

§ 52.36 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of sulfur dioxide?

* * * * *

(e) Notwithstanding any provisions of paragraphs (a) through (c) of this section, subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraphs (a) through (e) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

■ 9. Sections §§ 52.38 and 52.39 are added to subpart A to read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) under the Transport Rule (TR) relating to emissions of nitrogen oxides?

(a)(1) The TR NO_X Annual Trading Program provisions set forth in subpart AAAAA of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to annual emissions of nitrogen oxides (NO_X).

(2) The provisions of subpart AAAAA of part 97 of this chapter apply to the sources in the following States and Indian country located within the borders of such States: Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

(3) Notwithstanding the provisions of paragraph (a)(1) of this section, a State listed in paragraph (a)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, as TR NO_X Annual allowance allocation provisions replacing the provisions in § 97.411(a) of this chapter with regard to the State and the control period in 2013, a list of TR NO_X Annual units and the amount of TR NO_X Annual allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and commenced commercial operation before January 1, 2010;

(ii) The total amount of TR NO_X Annual allowance allocations on the list must not exceed the amount, under § 97.410(a) of this chapter for the State and the control period in 2013, of TR NO_X Annual trading budget minus the sum of the new unit set-aside and Indian country new unit set-aside;

(iii) The list must be submitted electronically in a format specified by the Administrator; and

(iv) The SIP revision must not provide for any change in the units and allocations on the list after approval of the SIP revision by the Administrator and must not provide for any change in any allocation determined and recorded by the Administrator under subpart AAAAA of part 97 of this chapter;

(v) Provided that:

(A) By October 17, 2011, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraph (a)(3)(i) through (iv) of this section by April 1, 2012; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (a)(3)(v)(A) of this section by April 1, 2012.

(4) Notwithstanding the provisions of paragraph (a)(1) of this section, a State listed in paragraph (a)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations revising subpart AAAAA of part 97 of this chapter as follows and not making any other substantive revisions of that subpart:

(i) The State may adopt, as TR NO_X Annual allowance allocation or auction provisions replacing the provisions in §§ 97.411(a) and (b)(1) and 97.412(a) of this chapter with regard to the State and the control period in 2014 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR NO_X Annual allowances, and may adopt, in addition to the definitions in § 97.402 of this chapter, one or more definitions that shall apply only to terms as used in the adopted TR NO_X Annual allowance allocation or auction provisions, if such methodology—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR NO_X Annual allowances for any such control period not exceeding the amount, under §§ 97.410(a) and 97.421 of this chapter for the State and such control period, of the TR NO_X Annual trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR NO_X Annual allowances already allocated and recorded by the Administrator.

(B) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Annual allowances for any such control period to any TR NO_X Annual units covered by § 97.411(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR NO_X Annual allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Annual allowances for any such control period to any TR NO_X Annual units covered by §§ 97.411(b)(1) and 97.412(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR NO_X Annual allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (a)(4)(i)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in

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any allocation determined and recorded by the Administrator under subpart AAAAA of part 97 of this chapter;

(ii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (a)(4)(i) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (a)(4)(i)(B) and (C) of this section for the first control period for which the State wants to make allocations or hold an auction under paragraph (a)(4)(i) of this section.

(5) Notwithstanding the provisions of paragraph (a)(1) of this section, a State listed in paragraph (a)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting in whole or in part, as appropriate, the deficiency in the SIP that is the basis for the TR Federal Implementation Plan set forth in paragraphs (a)(1) through (4) of this section, regulations that are substantively identical to the provisions of the TR NO_X Annual Trading Program set forth in §§ 97.402 through 97.435 of this chapter, except that the SIP revision:

(i) May adopt, as TR NO_X Annual allowance allocation or auction provisions replacing the provisions in §§ 97.411(a) and (b)(1) and 97.412(a) of this chapter with regard to the State and the control period in 2014 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR NO_X Annual allowances and that—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR NO_X Annual allowances for any such control period not exceeding the amount, under §§ 97.410(a) and 97.421 of this chapter for the State and such control period, of the TR NO_X Annual trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR NO_X Annual allowances already allocated and recorded by the Administrator.

(B) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Annual allowances for any such control period to any TR NO_X Annual units covered by § 97.411(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR NO_X Annual allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Annual allowances for any such control period to any TR NO_X Annual units covered by §§ 97.411(b)(1) and 97.412(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR NO_X Annual allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (a)(5)(i)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart AAAAA of part 97 of this chapter;

(ii) May adopt, in addition to the definitions in § 97.402 of this chapter, one or more definitions that shall apply only to terms as used in the TR NO_X Annual allowance allocation or auction provisions adopted under paragraph (a)(5)(i) of this section;

(iii) May substitute the name of the State for the term ''State'' as used in subpart AAAAA of part 97 of this chapter, to the extent the Administrator determines that such substitutions do not make substantive changes in the provisions in §§ 97.402 through 97.435 of this chapter; and

(iv) Must not include any of the references to, or requirements imposed on, any unit in Indian country within the borders of the State in the provisions in §§ 97.402 through 97.435 of this chapter and must not include the provisions in §§ 97.411(b)(2) and 97.412(b), all of which provisions will continue to apply under the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision;

(v) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.402 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.406(c)(2), 97.425, and the portions of other provisions referencing these sections and may modify the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(vi) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (a)(5)(i) through (iv) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (a)(5)(i)(B) and (C) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraphs (a)(5)(i) and (ii) of this section.

(6) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting in whole or in part, as appropriate, the SIP's deficiency that is the basis for the TR Federal Implementation Plan described in paragraphs (a)(1) through (5) of this section, the provisions of paragraph (a)(2) of this section will no longer apply to the sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State.

(7) Notwithstanding the provisions of paragraph (a)(6) of this section, if, at the time of such approval of the State's SIP revision, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in a State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The TR NO_X Ozone Season Trading Program provisions set forth in part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season, defined as May 1 through September 30 of a calendar year.

(2) The provisions of subpart BBBBB of part 97 of this chapter apply to

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sources in each of the following States and Indian country located within the borders of such States: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia.

(3) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, as TR NO_X Ozone Season allowance allocation provisions replacing the provisions in § 97.511(a) of this chapter with regard to the State and the control period in 2013, a list of TR NO_X Ozone Season units and the amount of TR NO_X Ozone Season allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and commenced commercial operation before January 1, 2010;

(ii) The total amount of TR NO_X Ozone Season allowance allocations on the list must not exceed the amount, under § 97.510(a) of this chapter for the State and the control period in 2013, of TR NO_X Ozone Season trading budget minus the sum of the new unit set-aside and Indian country new unit set-aside;

(iii) The list must be submitted electronically in a format specified by the Administrator; and

(iv) The SIP revision must not provide for any change in the units and allocations on the list after approval of the SIP revision by the Administrator and must not provide for any change in any allocation determined and recorded by the Administrator under subpart BBBBB of part 97 of this chapter;

(v) Provided that:

(A) By October 17, 2011, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraph (b)(3)(i) through (iv) of this section by April 1, 2012; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(3)(v)(A) of this section by April 1, 2012.

(4) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations revising subpart BBBBB of part 97 of this chapter as follows and not making any other substantive revisions of that subpart:

(i) The State may adopt, as applicability provisions replacing the provisions in §§ 97.504(a)(1) and (2) of this chapter, provisions substantively identical to those provisions, except that the words ''more than 25 MWe'' are replaced, whenever such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more''; or

(ii) The State may adopt, as TR NO_X Ozone Season allowance allocation or auction provisions replacing the provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to the control period in 2014 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR NO_X Ozone Season allowances, and may adopt, in addition to the definitions in § 97.502 of this chapter, one or more definitions that shall apply only to terms as used in the adopted TR NO_X Ozone Season allowance allocation or auction provisions, if such methodology—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR NO_X Ozone Season allowances for any such control period not exceeding the amount, under §§ 97.510(a) and 97.521 of this chapter for the State and such control period, of the TR NO_X Ozone Season trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR NO_X Ozone Season allowances already allocated and recorded by the Administrator.

(B) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Ozone Season allowances for any such control period to any TR NO_X Ozone Season units covered by § 97.511(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR NO_X Ozone Season allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR NO_X Ozone Season allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Ozone Season allowances for any such control period to any TR NO_X Ozone Season units covered by §§ 97.511(b)(1) and 97.512(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR NO_X Ozone Season allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (b)(4)(ii)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart BBBBB of part 97 of this chapter;

(iii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(4)(i) or (ii) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (b)(4)(ii)(B) and (C) of this section applicable to the first control period for which the State wants to replace the applicability provisions, make allocations, or hold an auction under paragraph (b)(4)(i) or (ii) of this section.

(5) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting in whole or in part, as appropriate, the deficiency in the SIP that is the basis for the TR Federal Implementation Plan set forth in paragraphs (b)(1) through (4) of this section, regulations that are substantively identical to the provisions of the TR NO_X Ozone Season Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

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(i) May adopt, as applicability provisions replacing the provisions in §§ 97.504(a)(1) and (2) of this chapter, provisions substantively identical to those provisions, except that the words ''more than 25 MWe'' are replaced, whenever such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more''; or

(ii) May adopt, as TR NO_X Ozone Season allowance allocation provisions replacing the provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to the control period in 2014 and any subsequent year, any methodology under which the State or the permitting authority allocates auctions TR NO_X Ozone Season allowances and that—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR NO_X Ozone Season allowances for any such control period not exceeding the amount, under §§ 97.510(a) and 97.521 of this chapter for the State and such control period, of the TR NO_X Ozone Season trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR NO_X Ozone Season allowances already allocated and recorded by the Administrator.

(B) Requires, to the extent the State adopts provisions for allocations or auction of TR NO_X Ozone Season allowances for any such control period to any TR NO_X Ozone Season units covered by § 97.511(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR NO_X Ozone Season allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR NO_X Ozone Season allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of TR NO_X Ozone Season allowances for any control period to any TR NO_X Ozone Season units covered by §§ 97.511(b)(1) and 97.512(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR NO_X Ozone Season allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (b)(5)(ii)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart BBBBB of part 97 of this chapter;

(iii) May adopt in addition to the definitions in § 97.502 of this chapter, one or more definitions that shall apply only to terms as used in the TR NO_X Ozone Season allowance allocation or auction provisions adopted under paragraph (b)(5)(ii) of this section;

(iv) May substitute the name of the State for the term ''State'' as used in subpart BBBBB of part 97 of this chapter, to the extent the Administrator determines that such substitutions do not make substantive changes in the provisions in §§ 97.502 through 97.535 of this chapter; and

(v) Must not include any of the references to, or requirements imposed on, any unit in Indian country within the borders of the State in the provisions in §§ 97.502 through 97.535 of this chapter and must not include the provisions in §§ 97.511(b)(2) and 97.512(b), all of which provisions will continue to apply under the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision;

(vi) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.502 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.506(c)(2), 97.525, and the portions of other provisions referencing these sections and may modify the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(vii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(5)(i) through (v) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (5)(ii)(B) and (C) of this section applicable to the first control period for which the State wants to replace the applicability provisions, make allocations, or hold an auction under paragraphs (b)(5)(ii) and (iii) of this section.

(6) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting in whole or in part, as appropriate, the SIP's deficiency that is the basis for the TR Federal Implementation Plan set forth in paragraphs (b)(1) through (5) of this section, the provisions of paragraph (b)(2) of this section will no longer apply to sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State.

(7) Notwithstanding the provisions of paragraph (b)(6) of this section, if, at the time of such approval of the State's SIP revision, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in a State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Transport Rule (TR) relating to emissions of sulfur dioxide?

(a) The TR SO_2 Group 1 Trading Program provisions and the TR SO_2 Group 2 Trading Program provisions set forth respectively in subparts CCCCC and DDDDD of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of sulfur dioxide (SO_2).

(b) The provisions of subpart CCCCC of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States: Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

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(c) The provisions of subpart DDDDD of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States: Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina, and Texas.

(d) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (b) of this section may adopt and include in a SIP revision, and the Administrator will approve, as TR SO_2 Group 1 allowance allocation provisions replacing the provisions in § 97.611(a) of this chapter with regard to the State and the control period in 2013, a list of TR SO_2 Group 1 units and the amount of TR SO_2 Group 1 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(1) All of the units on the list must be units that are in the State and commenced commercial operation before January 1, 2010;

(2) The total amount of TR SO_2 Group 1 allowance allocations on the list must not exceed the amount, under § 97.610(a) of this chapter for the State and the control period in 2013, of TR SO_2 Group 1 trading budget minus the sum of the new unit set-aside and Indian country new unit set-aside;

(3) The list must be submitted electronically in a format specified by the Administrator; and

(4) The SIP revision must not provide for any change in the units and allocations on the list after approval of the SIP revision by the Administrator and must not provide for any change in any allocation determined and recorded by the Administrator under subpart CCCCC of part 97 of this chapter;

(5) Provided that:

(i) By October 17, 2011, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraph (d)(1) through (4) of this section by April 1, 2012; and

(ii) The State must submit to the Administrator a complete SIP revision described in paragraph (d)(5)(i) of this section by April 1, 2012.

(e) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (b) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations revising subpart CCCCC of part 97 of this chapter as follows and not making any other substantive revisions of that subpart:

(1) The State may adopt, as TR SO_2 Group 1 allowance allocation or auction provisions replacing the provisions in §§ 97.611(a) and (b)(1) and 97.612(a) of this chapter with regard to the control period in 2014 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR SO_2 Group 1 allowances and may adopt, in addition to the definitions in § 97.602 of this chapter, one or more definitions that shall apply only to terms as used in the adopted TR SO_2 Group 1 allowance allocation or auction provisions, if such methodology—

(i) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR SO_2 Group 1 allowances for any such control period not exceeding the amount, under §§ 97.610(a) and 97.621 of this chapter for the State and such control period, of the TR SO_2 Group 1 trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR SO_2 Group 1 allowances already allocated and recorded by the Administrator.

(ii) Requires, to the extent the State adopts provisions for allocations or auction of TR SO_2 Group 1 allowances for any such control period to any TR SO_2 Group 1 units covered by § 97.611(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR SO_2 Group 1 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(iii) Requires, to the extent the State adopts provisions for allocations or auctions of TR SO_2 Group 1 allowances for any such control period to any TR SO_2 Group 1 units covered by §§ 97.611(b)(1) and 97.612(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR SO_2 Group 1 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(iv) Does not provide for any change, after the submission deadlines in paragraphs (e)(1)(ii) and (iii) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart CCCCC of part 97 of this chapter;

(2) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (e)(1) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (e)(1)(ii) and (iii) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (e)(1) of this section.

(f) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (b) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting in whole or in part, as appropriate, the deficiency in the SIP that is the basis for the TR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section, regulations that are substantively identical to the provisions of the TR SO_2 Group 1 Trading Program set forth in §§ 97.602 through 97.635 of this chapter, except that the SIP revision:

(1) May adopt, as TR SO_2 Group 1 allowance allocation or auction provisions replacing the provisions in §§ 97.611(a) and (b)(1) and 97.612(a) of this chapter with regard to the control period in 2014 and any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR SO_2 Group 1 allowances and that—

(i) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR SO_2 Group 1 allowances for such control period not exceeding the amount, under §§ 97.610(a) and 97.621 of this chapter for the State and such control period, of the TR SO_2 Group 1 trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR SO_2 Group 1 allowances already allocated and recorded by the Administrator.

(ii) Requires, to the extent the State adopts provisions for allocations or auction of TR SO_2 Group 1 allowances for any such control period to any TR

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SO_2 Group 1 units covered by § 97.611(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR SO_2 Group 1 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(iii) Requires, to the extent the State adopts provisions for allocations or auctions of TR SO_2 Group 1 allowances for any such control period to any TR SO_2 Group 1 units covered by §§ 97.611(b)(1) and 97.612(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR SO_2 Group 1 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(iv) Does not provide for any change, after the submission deadlines in paragraphs (f)(2)(ii) and (iii) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart CCCCC of part 97 of this chapter;

(2) May adopt, in addition to the definitions in § 97.602 of this chapter, one or more definitions that shall apply only to terms as used in the TR SO_2 Group 1 allowance allocation or auction provisions adopted under paragraph (f)(1) of this section;

(3) May substitute the name of the State for the term ''State'' as used in subpart CCCCC of part 97 of this chapter, to the extent the Administrator determines that such substitutions do not make substantive changes in the provisions in §§ 97.602 through 97.635 of this chapter; and

(4) Must not include any of the references to, or requirements imposed on, any unit in Indian country within the borders of the State in the provisions in §§ 97.602 through 97.635 of this chapter and must not include the provisions in §§ 97.611(b)(2) and 97.612(b), all of which provisions will continue to apply under the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision;

(5) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.602 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.606(c)(2), 97.625, and the portions of other provisions referencing these sections and may modify the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(6) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (f)(1) through (4) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (f)(1)(ii) and (iii) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (f)(1)(ii) and (iii) of this section.

(g) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (c) of this section may adopt and include in a SIP revision, and the Administrator will approve, as TR SO_2 Group 2 allowance allocation provisions replacing the provisions in § 97.711(a) of this chapter with regard to the control period in 2013, a list of TR SO_2 Group 2 units and the amount of TR SO_2 Group 2 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(1) All of the units on the list must be units that are in the State and commenced commercial operation before January 1, 2010;

(2) The total amount of TR SO_2 Group 2 allowance allocations on the list must not exceed the amount, under § 97.710(a) of this chapter for the State and the control period in 2013, of TR SO_2 Group 2 trading budget minus the sum of the new unit set-aside and Indian country new unit set-aside;

(3) The list must be submitted electronically in a format specified by the Administrator; and

(4) The SIP revision must not provide for any change in the units and allocations on the list after approval of the SIP revision by the Administrator and must not provide for any change in any allocation determined and recorded by the Administrator under subpart DDDDD of part 97 of this chapter;

(5) Provided that:

(i) By October 17, 2011, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraph (g)(1) through (4) of this section by April 1, 2012; and

(ii) The State must submit to the Administrator a complete SIP revision described in paragraph (g)(5)(i) of this section by April 1, 2012.

(h) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (c) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations revising subpart DDDDD of part 97 of this chapter as follows and not making any other substantive revisions of that subpart:

(1) The State may adopt, as TR SO_2 Group 2 allowance allocation or auction provisions replacing the provisions in §§ 97.711(a) and (b)(1) and 97.712(a) of this chapter with regard to the control period in 2014 and any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR SO_2 Group 2 allowances and may adopt, in addition to the definitions in § 97.702 of this chapter, one or more definitions that shall apply only to terms as used in the adopted TR SO_2 Group 2 allowance allocation or auction provisions, if such methodology—

(i) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR SO_2 Group 2 allowances for any such control period not exceeding the amount, under §§ 97.710(a) and 97.721 of this chapter for the State and such control period, of the TR SO_2 Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR SO_2 Group 2 allowances already allocated and recorded by the Administrator.

(ii) Requires, to the extent the State adopts provisions for allocations or auction of TR SO_2 Group 2 allowances for any such control period to any TR SO_2 Group 2 units covered by § 97.711(a) of this chapter, that the State or the permitting authority submit such

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allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR SO_2 Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(iii) Requires, to the extent the State adopts provisions for allocations or auctions of TR SO_2 Group 2 allowances for any such control period to any TR SO_2 Group 2 units covered by §§ 97.711(b)(1) and 97.712(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR SO_2 Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(iv) Does not provide for any change, after the submission deadlines in paragraphs (h)(1)(ii) and (iii) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart DDDDD of part 97 of this chapter;

(2) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (h)(1) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (h)(1)(ii) and (iii) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (h)(1)(ii) and (iii) of this section.

(i) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (c) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting in whole or in part, as appropriate, the deficiency in the SIP that is the basis for the TR Federal Implementation Plan set forth in paragraphs (a), (c), (g), and (h) of this section, regulations that are substantively identical to the provisions of the TR SO_2 Group 2 Trading Program set forth in §§ 97.702 through 97.735 of this chapter, except that the SIP revision:

(1) May adopt, as TR SO_2 Group 2 allowance allocation or auction provisions replacing the provisions in §§ 97.711(a) and (b)(1) and 97.712(a) of this chapter with regard to the control period in 2014 and any subsequent year, any methodology under which the State or the permitting authority allocates or auctions TR SO_2 Group 2 allowances and that—

(i) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of TR SO_2 Group 2 allowances for any such control period not exceeding the amount, under §§ 97.710(a) and 97.721 of this chapter for the State and such control period, of the TR SO_2 Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any TR SO_2 Group 2 allowances already allocated and recorded by the Administrator.

(ii) Requires, to the extent the State adopts provisions for allocations or auction of TR SO_2 Group 2 allowances for any such control period to any TR SO_2 Group 2 units covered by § 97.711(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of TR SO_2 Group 1 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which TR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to administrator
2014	June 1, 2013.
2015	June 1, 2013.
2016	June 1, 2014.
2017	June 1, 2014.
2018	June 1, 2015.
2019	June 1, 2015.
2020 and any year thereafter.	June 1 of the fourth year before the year of the control period.

(iii) Requires, to the extent the State adopts provisions for allocations or auctions of TR SO_2 Group 2 allowances for any such control period to any TR SO_2 Group 2 units covered by §§ 97.711(b)(1) and 97.712(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of TR SO_2 Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(iv) Does not provide for any change, after the submission deadlines in paragraphs (i)(1)(ii) and (iii) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart DDDDD of part 97 of this chapter;

(2) May adopt, in addition to the definitions in § 97.702 of this chapter, one or more definitions that shall apply only to terms as used in the TR SO_2 Group 2 allowance allocation or auction provisions adopted under paragraph (i)(1) of this section;

(3) May substitute the name of the State for the term ''State'' as used in subpart DDDDD of part 97 of this chapter, to the extent the Administrator determines that such substitutions do not make substantive changes in the provisions in §§ 97.702 through 97.735 of this chapter; and

(4) Must not include any of the references to, or requirements imposed on, any unit in Indian country within the borders of the State in the provisions in §§ 97.702 through 97.735 of this chapter and must not include the provisions in §§ 97.711(b)(2) and 97.712(b), all of which provisions will continue to apply under the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision;

(5) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.702 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.706(c)(2), 97.725, and the portions of other provisions referencing these sections and may modify the portion of the TR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(6) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (i)(1) through (4) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs

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(i)(1)(ii) and (iii) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraphs (i)(1)(ii) and (iii) of this section.

(j) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting in whole or in part, as appropriate, the SIP's deficiency that is the basis for the TR Federal Implementation Plan, the provisions of paragraph (b) and (c) of this section, as applicable, will no longer apply to sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State.

(k) Notwithstanding the provisions of paragraph (j) of this section, if, at the time of such approval of the State's SIP revision, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter, to units in a State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances, or of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances, as applicable, to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart B—Alabama

■ 10. Section 52.54 is added to read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Alabama and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Alabama and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of the Alabama's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 11. Section 52.55 is added to read as follows:

§ 52.55 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Alabama and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart E—Arkansas

■ 12. Section 52.184 is added to read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to

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units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart I—Delaware

■ 13. Section 52.440 is amended by adding a new paragraph (c) to read as follows:

§ 52.440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

■ 14. Section 52.441 is amended by designating the existing text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.441 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart J—District of Columbia

■ 15. Section 52.484 is amended by adding a new paragraph (c) to read as follows:

§ 52.484 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

■ 16. Section 52.485 is amended by designating the existing text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.485 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart K—Florida

■ 17. Section 52.540 is added to read as follows:

§ 52.540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Florida and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units located in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Florida's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Florida's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the

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time of the approval of Florida's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart L—Georgia

■ 18. Section 52.584 is added to read as follows:

§ 52.584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Georgia and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Georgia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Georgia's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Georgia and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Georgia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Georgia's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 19. Section 52.585 is added to read as follows:

§ 52.585 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Georgia and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Georgia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Georgia's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart O—Illinois

■ 20. Section 52.745 is added to read as follows:

§ 52.745 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Illinois and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Illinois' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Illinois' SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Illinois and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Illinois' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Illinois' SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this

chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 21. Section 52.746 is added to read as follows:

§ 52.746 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Illinois and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Illinois' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Illinois' SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart P—Indiana

■ 22. Section 52.789 is added to read as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Indiana and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Indiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Indiana's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Indiana and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Indiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Indiana's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 23. Section 52.790 is added to read as follows:

§ 52.790 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Indiana and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Indiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39 except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Indiana's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Q—Iowa

■ 24. Section 52.840 is added to read as follows:

§ 52.840 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Iowa and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Iowa's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) [Reserved]

■ 25. Section 52.841 is added to read as follows:

§ 52.841 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Iowa and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Iowa's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart R—Kansas

■ 26. Section 52.882 is added to read as follows:

§ 52.882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Kansas and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Kansas' State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Kansas' SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Kansas' SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) [Reserved]

■ 27. Section 52.883 is added to read as follows:

§ 52.883 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Kansas and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated with regard to sources and units in the State by the promulgation of an approval by the Administrator of a revision to Kansas' State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Kansas' SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Kansas' SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart S—Kentucky

■ 28. Section 52.940 is added to read as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Kentucky and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Kentucky's State

Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Kentucky's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Kentucky and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Kentucky's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Kentucky's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 29. Section 52.941 is added to read as follows:

§ 52.941 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Kentucky and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Kentucky's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Kentucky's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart T—Louisiana

■ 30. Section 52.984 is amended by adding new paragraphs (c) and (d) to read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

(d)(1) The owner and operator of each source and each unit located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart V—Maryland

■ 31. Section 52.1084 is added to read as follows:

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§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Maryland and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Maryland's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Maryland's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Maryland and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Maryland's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Maryland's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 32. Section 52.1085 is added to read as follows:

§ 52.1085 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Maryland and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Maryland's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Maryland's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart X—Michigan

■ 33. Section 52.1186 is amended by adding new paragraphs (c) and (d) to read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

(d)(1) The owner and operator of each source and each unit located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of

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subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(e) [Reserved]

■ 34. Section 52.1187 is amended by designating the existing text as paragraph (a) and adding new paragraphs (b) and (c) to read as follows:

§ 52.1187 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

(c)(1) The owner and operator of each source and each unit located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Maryland's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Y—Minnesota

■ 35. Section 52.1240 is amended by adding paragraph (c) to read as follows:

§ 52.1240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 36. Section 52.1241 is amended by adding paragraph (c) to read as follows:

§ 52.1241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(c)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Z—Mississippi

■ 37. Section 52.1284 is added to read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of

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this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart AA—Missouri

■ 38. Section 52.1326 is added to read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) [Reserved]

■ 39. Section 52.1327 is added to read as follows:

§ 52.1327 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart CC—Nebraska

■ 40. Section 52.1428 is added to read as follows:

§ 52.1428 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Nebraska and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Nebraska's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nebraska's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Nebraska's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 41. Section 52.1429 is added to read as follows:

§ 52.1429 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Nebraska and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Nebraska's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to

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sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nebraska's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Nebraska's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart FF—New Jersey

■ 42. Section 52.1584 is amended by adding new paragraphs (c), (d), and (e) to read as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

(d)(1) The owner and operator of each source and each unit located in the State of New Jersey and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to New Jersey's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of New Jersey's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(e)(1) The owner and operator of each source and each unit located in the State of New Jersey and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to New Jersey's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (e)(1) of this section, if, at the time of the approval of New Jersey's SIP revision described in paragraph (e)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 43. Section 52.1585 is amended by designating the existing text as paragraph (a) and adding new paragraphs (b) and (c) to read as follows:

§ 52.1585 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

(c)(1) The owner and operator of each source and each unit located in the State of New Jersey and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to New Jersey's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of New Jersey's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation

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of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart HH—New York

■ 44. Section 52.1684 is revised to read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of New York and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of New York and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 45. Section 52.1685 is added to read as follows:

§ 52.1685 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of New York and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart II—North Carolina

■ 46. Section 52.1784 is revised to read as follows:

§ 52.1784 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of North Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of North Carolina's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall

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continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of North Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's SIP.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of North Carolina's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 47. Section 52.1785 is revised to read as follows:

§ 52.1785 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of North Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to North Carolina's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of North Carolina's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart KK—Ohio

■ 48. Section 52.1882 is added to read as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Ohio and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Ohio's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Ohio's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Ohio and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Ohio's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Ohio's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 49. Section 52.1883 is added to read as follows:

§ 52.1883 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Ohio and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Ohio's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Ohio's SIP

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revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart NN—Pennsylvania

■ 50. Section 52.2040 is added to read as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Pennsylvania and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Pennsylvania's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Pennsylvania's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Pennsylvania and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Pennsylvania's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Pennsylvania's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 51. Section 52.2041 is added to read as follows:

§ 52.2041 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Pennsylvania and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Pennsylvania's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Pennsylvania's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart PP—South Carolina

■ 52. Section 52.2140 is revised to read as follows:

§ 52.2140 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of South Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of South Carolina's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of South Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be

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eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's SIP.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of South Carolina's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 53. Section 52.2141 is revised to read as follows:

§ 52.2141 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of South Carolina and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to South Carolina's SIP.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of South Carolina's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart RR—Tennessee

■ 54. Section 52.2240 is amended by adding new paragraphs (c), (d), and (e) to read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

(d)(1) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(e)(1) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an

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approval by the Administrator of a revision to Tennessee's SIP.

(2) Notwithstanding the provisions of paragraph (e)(1) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (e)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 55. Section 52.2241 is amended by designating the existing text as paragraph (a) and adding new paragraphs (b) and (c) to read as follows:

§ 52.2241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

(c)(1) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart SS—Texas

■ 56. Section 52.2283 is amended by adding new paragraphs (b), (c) and (d) to read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AA through II of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraph (a) of this section relating to NO_X annual emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II of part 97 of this chapter;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods.

(c)(1) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(d)(1) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this

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chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 57. Section 52.2284 is amended by designating the existing text as paragraph (a) and adding new paragraphs (b) and (c) to read as follows:

§ 52.2284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

(c)(1) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart DDDDD of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart VV—Virginia

■ 58. Section 52.2440 is added to read as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Virginia and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Virginia's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of Virginia and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Virginia's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 59. Section 52.2241 is added to read as follows:

§ 52.2241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Virginia and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of Virginia's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart XX—West Virginia

■ 60. Section 52.2540 is added to read as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of West Virginia and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to West Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of West Virginia's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b)(1) The owner and operator of each source and each unit located in the State of West Virginia and for which requirements are set forth under the TR NO_X Ozone Season Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to West Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of West Virginia's SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Ozone Season allowances under subpart BBBBB of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Ozone Season allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 61. Section 52.2541 is added to read as follows:

§ 52.2541 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of West Virginia and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to West Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional.

(b) Notwithstanding the provisions of paragraph (a) of this section, if, at the time of the approval of West Virginia's SIP revision described in paragraph (a) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart YY—Wisconsin

■ 62. Section 52.2587 is amended by adding new paragraphs (c) and (d) to read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter;

(3) By November 7, 2011, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By November 7, 2011, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2012 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

(d)(1) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the TR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.38(a), except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the

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time of the approval of Wisconsin's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of TR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart AAAAA of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR NO_X Annual allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 63. Section 52.2588 is amended by designating the existing text as paragraph (a) and adding new paragraphs (b) and (c) to read as follows:

§ 52.2588 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

(c)(1) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the TR SO_2 Group 1 Trading Program in subpart CCCCC of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting in part the SIP's deficiency that is the basis for the TR Federal Implementation Plan under § 52.39, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (c)(1) of this section, the Administrator has already started recording any allocations of TR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart CCCCC of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of TR SO_2 Group 1 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

PART 72—[AMENDED]

■ 64. The authority citation for part 72 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

§ 72.2 [Amended]

■ 65. Section 72.2 is amended by removing the definition of ''Interested person''.

PART 78—[AMENDED]

■ 66. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

■ 67. Section 78.1 is amended by adding paragraphs (b)(13) through (b)(16) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(13) Under subpart AAAAA of part 97 of this chapter,

(i) The decision on allocation of TR NO_X Annual allowances under § 97.411(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Annual allowances under § 97.423 of this chapter.

(iii) The decision on the deduction of TR NO_X Annual allowances under §§ 97.424 and 97.425 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.427 of this chapter.

(v) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Annual allowances based on the information as adjusted under § 97.428 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.435 of this chapter.

(14) Under subpart BBBBB of part 97 of this chapter,

(i) The decision on allocation of TR NO_X Ozone Season allowances under § 97.511(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Ozone Season allowances under § 97.523 of this chapter.

(iii) The decision on the deduction of TR NO_X Ozone Season allowances under §§ 97.524 and 97.525 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.527 of this chapter.

(v) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Ozone Season allowances based on the information as adjusted under § 97.528 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.535 of this chapter.

(15) Under subpart CCCCC of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 1 allowances under § 97.611(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.623 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.624 and 97.625 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.627 of this chapter.

(v) The adjustment of information in a submission and the decision on the deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.628 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.635 of this chapter.

(16) Under subpart DDDDD of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 2 allowances under § 97.711(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.723 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.724 and 97.725 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.727 of this chapter.

(v) The adjustment of information in a submission and the decision on the

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deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.728 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.735 of this chapter.

* * * * *

■ 68. Section 78.2 is revised to read as follows:

§ 78.2 General.

(a) *Definitions.* (1) The terms used in this subpart with regard to a decision of the Administrator that is appealed under this section shall have the meaning as set forth in the regulations under which the Administrator made such decision and as set forth in paragraph (a)(2) of this section.

(2) *Interested person* means, with regard to a decision of the Administrator:

(i) Any person who submitted comments, or testified at a public hearing, pursuant to an opportunity for comment provided by the Administrator as part of the process of making such decision;

(ii) Who submitted objections pursuant to an opportunity for objections provided by the Administrator as part of the process of making such decision; or

(iii) Who submitted, to the Administrator and in a format prescribed by the Administrator, his or her name, service address, telephone number, and facsimile number and identified such decision in order to be placed on a list of persons interested in such decision;

(iv) Provided that the Administrator may update the list of interested persons from time to time by requesting additional written indication of continued interest from the persons listed and may delete from the list the name of any person failing to respond as requested.

(b) *Availability of information.* The availability to the public of information provided to, or otherwise obtained by, the Administrator under this subpart shall be governed by part 2 of this chapter.

(c) *Computation of time.* (1) In computing any period of time prescribed or allowed under this part, except as otherwise provided, the day of the event from which the period begins to run shall not be included, and Saturdays, Sundays, and federal holidays shall be included. When the period ends on a Saturday, Sunday, or federal holiday, the stated period shall be extended to include the next business day.

(2) Where a document is served by first class mail or commercial delivery service, but not by overnight or same-day delivery, 5 days shall be added to the time prescribed or allowed under this part for the filing of a responsive document or for otherwise responding.

■ 69. Section 78.3 is amended by:

■ a. In paragraphs (a)(1)(iii), (a)(3)(ii), (a)(4)(ii), (a)(5)(ii), (a)(6)(ii), (a)(7)(ii), (a)(8)(ii), and (a)(9)(ii), adding, after the word ''person'', the words ''with regard to the decision''.

■ b. Adding paragraph (a)(10);

■ c. In paragraph (b)(3)(i), removing the words ''paragraph (a)(1) and (2)'' and adding, in their place, the words ''paragraph (a)(1), (2), and (10)''; and

■ d. Adding paragraph (d)(11) to read as follows:

§ 78.3 Petition for administrative review and request or evidentiary hearing.

(a) * * *

(10) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAAAA, BBBBB, CCCCC, and DDDDD of part 97 of this chapter:

(i) The designated representative for a unit or source, or the authorized account representative for any Allowance Management System account, covered by the decision; or

(ii) Any interested person with regard to the decision.

* * * * *

(d) * * *

(11) Any provision or requirement of subparts AAAAA, BBBBB, CCCCC, or DDDDD of part 97 of this chapter, including the standard requirements under § 97.406, § 97.506, § 97.606, or § 97.706 of this chapter and any emission monitoring or reporting requirements.

* * * * *

■ 70. Section 78.4 is amended by:

■ a. Revising paragraph (a) by:

■ i. Removing the first, second, third, fourth, fifth, and last sentences;

■ ii. In the sixth and seventh sentences, removing the words ''interest in'' and adding, in their place, the words ''ownership interest with respect to'';

■ iii. Redesignating the paragraph as paragraph (a)(1)(iii); and

■ b. Adding paragraphs (a)(1) introductory text, (a)(1)(i), and (a)(1)(ii); and

■ c. Revising paragraph (a)(2) to read as follows:

§ 78.4 Filings.

(a)(1) All original filings made under this part shall be signed by the person making the filing or by an attorney or authorized representative, in accordance with the following requirements:

(i) Any filings on behalf of owners and operators of a affected unit or affected source, TR NO_X Annual unit or TR NO_X Annual source, TR NO_X Ozone Season unit or TR NO_X Ozone Season source, TR SO_2 Group 1 unit or TR SO_2 Group 1 source, TR SO_2 Group 2 unit or TR SO_2 Group 2 source, or a unit for which a TR opt-in application is submitted and not withdrawn shall be signed by the designated representative. Any filing on behalf of persons with an ownership interest with respect to allowances, TR NO_X Annual allowances, TR NO_X Ozone Season allowances, TR SO_2 Group 1 allowances, or TR SO_2 Group 2 allowances in a general account shall be signed by the authorized account representative.

(ii) Any filings on behalf of owners and operators of a NO_X Budget unit or NO_X Budget source shall be signed by the NO_X authorized account representative. Any filing on behalf of persons with an ownership interest with respect to NO_X allowances in a general account shall be signed by the NO_X authorized account representative.

* * * * *

(2) The name, address, e-mail address (if any), telephone number, and facsimile number (if any) of the person making the filing shall be provided with the filing.

* * * * *

§ 78.5 [Amended]

■ 71. Section 78.5 is amended by, in paragraph (a):

■ a. Removing the words''public comment prior to'' and adding, in their place, the words ''submission of public comments or objections prior to'';

■ b. Removing the words''public comment period'' whenever they appear and adding, in their place, the words ''period for submission of public comments or objections''.

§ 78.12 [Amended]

■ 72. Section 78.12 is amended by, in paragraph (a), removing the words ''public comment'' and adding, in their place, the words ''submission of public comments or objections''.

PART 97—[AMENDED]

■ 73. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

■ 74. Part 97 is amended by adding subpart AAAAA to read as follows:

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Subpart AAAAA—TR NO_X Annual Trading Program

Subpart AAAAA—TR NO_X Annual Trading Program

§ 97.401 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and § 52.38 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.402 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to TR NO_X Annual allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.38(a)(3), (4), or (5) of this chapter, of the amount of such TR NO_X Annual allowances to be initially credited, at no cost to the recipient, to:

(1) A TR NO_X Annual unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a TR NO_X Annual unit qualifying for an initial credit, a credit in the amount of zero TR NO_X Annual allowances, the TR NO_X Annual unit will be treated as being allocated an amount (*i.e.,* zero) of TR NO_X Annual allowances.

Allowable NO_X *emission rate* means, for a unit, the most stringent State or federal NO_X emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit's heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Annual allowances under the TR NO_X Annual Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Annual allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Annual allowance transfer must be submitted for recordation in a TR NO_X Annual source's compliance account in order to be available for use in complying with the source's TR NO_X Annual emissions limitation for such control period in accordance with §§ 97.406 and 97.424.

Alternate designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.425(b)(3) for certain owners and operators of a group of one or more TR NO_X Annual sources and units in a given State (and Indian country within the borders of such State), in which are held TR NO_X Annual allowances available for use for a control period in a given year in complying with the TR NO_X Annual assurance provisions in accordance with §§ 97.406 and 97.425.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Annual allowances held in the general account and, for a TR NO_X Annual source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use

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under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organicresource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means ''coal'' as defined in § 72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.405.

(i) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.405, for a unit that is not a TR NO_X Annual unit under § 97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Annual unit under § 97.404.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for

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commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§ 97.413(a) and 97.415(a) as the designated representative for a group of one or more TR NO_X Annual sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.406(c)(2)(iii), the common designated representative's share of the State NO_X Annual trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Annual units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NO_X emissions during such control period from a group of one or more TR NO_X Annual units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NO_X Annual trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR NO_X Annual allowances allocated for such control period to a group of one or more TR NO_X Annual units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR NO_X Annual allowances purchased by an owner or operator of such TR NO_X Annual units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR NO_X Annual units in accordance with the TR NO_X Annual allowance auction provisions in a SIP revision approved by the Administrator under §52.38(a)(4) or (5) of this chapter, multiplied by the sum of the State NO_X Annual trading budget under §97.410(a) and the State's variability limit under § 97.410(b) for such control period and divided by such State NO_X Annual trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR NO_X Annual allowances allocated under §§ 97.411 and 97.412 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Annual allowances for such control period equal to the unit's allowable NO_X emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Annual source under this subpart, in which any TR NO_X Annual allowance allocations to the TR NO_X Annual units at the source are recorded and in which are held any TR NO_X Annual allowances available for use for a control period in a given year in complying with the source's TR NO_X Annual emissions limitation in accordance with §§ 97.406 and 97.424.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.430 through 97.435. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.406(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and

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reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR NO_X Annual units at a TR NO_X Annual source during a control period in a given year that exceeds the TR NO_X Annual emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on ''average annual fuel consumption of fossil fuel'' in §§ 97.404(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means ''natural gas'' as defined in § 72.2 of this chapter.

Newly affected TR NO_X Annual unit means a unit that was not a TR NO_X Annual unit when it began operating but that thereafter becomes a TR NO_X Annual unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a TR NO_X Annual source or a TR NO_X Annual unit at a source respectively, any person who operates, controls, or supervises a TR NO_X Annual unit at the source or the TR NO_X Annual unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR NO_X Annual source or a TR NO_X Annual unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Annual unit at the source or the TR NO_X Annual unit;

(2) Any holder of a leasehold interest in a TR NO_X Annual unit at the source or the TR NO_X Annual unit, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR NO_X Annual unit; and 3) Any purchaser of power from a TR NO_X Annual unit at the source or the TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means ''permitting authority'' as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit, 33 percent of the unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to TR NO_X Annual allowances, the moving of TR NO_X

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Annual allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Annual allowance, the unique identification number assigned to each TR NO_X Annual allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR NO_X Annual Trading Program pursuant to § 52.38(a) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

LHV = HHV ¥ 10.55(W + 9H)

Where:

LHV = lower heating value of the form of energy in Btu/lb,
HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(a)(3), (4), or (5) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR NO_X Annual Trading Program.

TR NO_X Annual allowance deduction or *deduct TR NO_X Annual allowances* means the permanent withdrawal of TR NO_X Annual allowances by the Administrator from a compliance account (*e.g.*, in order to account for compliance with the TR NO_X Annual emissions limitation) or from an assurance account (*e.g.*, in order to account for compliance with the assurance provisions under §§ 97.406 and 97.425).

TR NO_X Annual allowances held or *hold TR NO_4 Annual allowances* means the TR NO_X Annual allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart.

TR NO_X Annual emissions limitation means, for a TR NO_X Annual source, the tonnage of NO_X emissions authorized in a control period in a given year by the TR NO_X Annual allowances available for deduction for the source under § 97.424(a) for such control period.

TR NO_X Annual source means a source that includes one or more TR NO_X Annual units.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with this subpart and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Annual unit means a unit that is subject to the TR NO_X Annual Trading Program.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and § 52.39(a), (b), (d) through (f), (j), and (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and 52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.403 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour lb—
pound mmBtu—million
Btu MWe—megawatt
electrical MWh—megawatt
hour NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million scfh—
standard cubic feet per hour SO_2—
sulfur dioxide
yr—year

§ 97.404 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR NO_X Annual units, and any source that includes one or more such units shall be a TR NO_X Annual source, subject to the requirements of this subpart: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Annual unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Annual unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR NO_X Annual unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR NO_X Annual unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR NO_X Annual unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a TR NO_X Annual unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR NO_X Annual unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR NO_X Annual unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, of the TR NO_X Annual Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: ''I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements

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and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) Response. The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Annual Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.405 Retired unit exemption.

(a)(1) Any TR NO_X Annual unit that is permanently retired shall be exempt from § 97.406(b) and (c)(1), § 97.424, and §§ 97.430 through 97.435.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Annual unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.406 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.430 through 97.435.

(2) The emissions data determined in accordance with §§ 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under §§ 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements.* (1) TR NO_X Annual emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under § 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii) If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under § 97.424(d); and

(B) The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Annual assurance provisions. (i) If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under § 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.425(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

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(ii) The owners and operators shall hold the TR NO_X Annual allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Annual trading budget under § 97.410(a) and the State's variability limit under § 97.410(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods. A TR NO_X Annual unit shall be subject to the requirements under paragraphs (c)(1) and (c)(2) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.430 through 97.435 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.416 for the designated representative for the source and each TR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.416 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, except as provided in § 97.418. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR NO_X Annual Trading Program or exemption under

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§ 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.407 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NO_X Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NO_X Annual Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.408 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Annual Trading Program are set forth in part 78 of this chapter.

§ 97.409 [Reserved]

§ 97.410 State NO_X Annual trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State NO_X Annual trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR NO_X Annual allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X Annual trading budget (tons)* for 2012 and 2013	New unit set-aside (tons) for 2012 and 2013	Indian country new unit set-aside (tons) for 2012 and 2013
Alabama	72,691	1,454	
Georgia	62,010	1,240	
Illinois	47,872	3,830	
Indiana	109,726	3,292	
Iowa	38,335	729	38
Kansas	30,714	583	31
Kentucky	85,086	3,403	
Maryland	16,633	333	
Michigan	60,193	1,144	60
Minnesota	29,572	561	30
Missouri	52,374	1,571	
Nebraska	26,440	1,825	26
New Jersey	7,266	145	
New York	17,543	508	18
North Carolina	50,587	2,984	51
Ohio	92,703	1,854	
Pennsylvania	119,986	2,400	
South Carolina	32,498	617	33
Tennessee	35,703	714	
Texas	133,595	3,874	134
Virginia	33,242	1,662	
West Virginia	59,472	2,974	
Wisconsin	31,628	1,866	32

State	NO_X Annual trading budget (tons)* for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
Alabama	71,962	1,439	
Georgia	40,540	811	
Illinois	47,872	3,830	
Indiana	108,424	3,253	
Iowa	37,498	712	38
Kansas	25,560	485	26
Kentucky	77,238	3,090	
Maryland	16,574	331	
Michigan	57,812	1,098	58
Minnesota	29,572	561	30
Missouri	48,717	1,462	
Nebraska	26,440	1,825	26
New Jersey	7,266	145	
New York	17,543	508	18
North Carolina	41,553	2,451	42
Ohio	87,493	1,750	
Pennsylvania	119,194	2,384	
South Carolina	32,498	617	33
Tennessee	19,337	387	

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State	NO_X Annual trading budget (tons)* for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
Texas	133,595	3,874	134
Virginia	33,242	1,662	
West Virginia	54,582	2,729	
Wisconsin	30,398	1,794	30

* Each trading budget includes the new unit set-aside and, where applicable, the Indian country new unit set-aside and does not include the variability limit.

(b) The States' variability limits for the State NO_X Annual trading budgets for the control periods in 2012 and thereafter are as follows:

State	Variability limits for 2012 and 2013	Variability limits for 2014 and thereafter
Alabama	13,084	12,953
Georgia	11,162	7,297
Illinois	8,617	8,617
Indiana	19,751	19,516
Iowa	6,900	6,750
Kansas	5,529	4,601
Kentucky	15,315	13,903
Maryland	2,994	2,983
Michigan	10,835	10,406
Minnesota	5,323	5,323
Missouri	9,427	8,769
Nebraska	4,759	4,759
New Jersey	1,308	1,308
New York	3,158	3,158
North Carolina	9,106	7,480
Ohio	16,687	15,749
Pennsylvania	21,597	21,455
South Carolina	5,850	5,850
Tennessee	6,427	3,481
Texas	24,047	24,047
Virginia	5,984	5,984
West Virginia	10,705	9,825
Wisconsin	5,693	5,472

§ 97.411 Timing requirements for TR NO_X Annual allowance allocations.

(a) *Existing units.* (1) TR NO_X Annual allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR NO_X Annual unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR NO_X Annual unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR NO_X Annual allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR NO_X Annual allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Annual allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO_X Annual allowance allocation to each TR NO_X Annual unit in a State, in accordance with § 97.412(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO_X Annual units) are in accordance with § 97.412(a)(2) through (7) and (12) and §§ 97.406(b)(2) and 97.430 through 97.435.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the

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Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.412(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR NO_X Annual allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR NO_X Annual units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO_X annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR NO_X annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO_X Annual units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR NO_X Annual allowance allocation to each TR NO_X Annual unit in accordance with § 97.412(a)(9), (10), and (12) and §§ 97.406(b)(2) and 97.430 through 97.435. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO_X Annual units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO_X Annual allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO_X Annual allowances in accordance with § 97.412(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO_X Annual allowance allocation to each TR NO_X Annual unit in Indian country within the borders of a State, in accordance with § 97.412(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO_X Annual units) are in accordance with § 97.412(b)(2) through (7) and (12) and §§ 97.406(b)(2) and 97.430 through 97.435.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.412(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR NO_X Annual allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR NO_X Annual units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO_X annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR NO_X annual units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO_X Annual units in the each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR NO_X Annual allowance allocation to each TR NO_X Annual unit in accordance with § 97.412(b)(9), (10), and (12) and §§ 97.406(b)(2) and 97.430 through 97.435. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO_X Annual units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO_X Annual allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO_X Annual allowances in accordance with § 97.412(b)(10).

(c) *Units incorrectly allocated* TR NO_X *Annual allowances.* (1) For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Annual allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(a)(3), (4), or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.412(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, where such control period and the recipient are covered by the

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provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR NO_X Annual unit under § 97.404 as of January 1, 2012 and is allocated TR NO_X Annual allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(a)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO_X Annual unit as of January 1, 2012 and is allocated TR NO_X Annual allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO_X Annual units as of January 1, 2012; or

(B) The recipient is not located as of January 1 of the control period in the State from whose NO_X Annual trading budget the TR NO_X Annual allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(a)(3), (4), or (5) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR NO_X Annual unit under § 97.404 as of January 1 of such control period and is allocated TR NO_X Annual allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(a)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO_X Annual unit as of January 1 of such control period and is allocated TR NO_X Annual allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO_X Annual units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR NO_X Annual allowances under § 97.421.

(3) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Annual allowances were recorded an amount of TR NO_X Annual allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Annual allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Annual allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Annual allowances.

(5)(i) With regard to the TR NO_X Annual allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR NO_X Annual allowances to the new unit set-aside for such control period for the State from whose NO_X Annual trading budget the TR NO_X Annual allowances were allocated; or

(B) If the State has a SIP revision approved under § 52.38(a)(4) or (5) covering such control period, include such TR NO_X Annual allowances in the portion of the State NO_X Annual trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR NO_X Annual allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR NO_X Annual allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under § 52.38(a)(4) or (5) covering such control period, include such TR NO_X Annual allowances in the portion of the State NO_X Annual trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR NO_X Annual allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR NO_X Annual allowances to the Indian country new unit set-aside for such control period.

§ 97.412 TR NO_X Annual allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR NO_X Annual units in each State, the Administrator will allocate TR NO_X Annual allowances to the TR NO_X Annual units as follows:

(1) The TR NO_X Annual allowances will be allocated to the following TR NO_X Annual units, except as provided in paragraph (a)(10) of this section:

(i) TR NO_X Annual units that are not allocated an amount of TR NO_X Annual allowances in the notice of data availability issued under § 97.411(a)(1);

(ii) TR NO_X Annual units whose allocation of an amount of TR NO_X Annual allowances for such control period in the notice of data availability issued under § 97.411(a)(1) is covered by § 97.411(c)(2) or (3);

(iii) TR NO_X Annual units that are allocated an amount of TR NO_X Annual allowances for such control period in the notice of data availability issued under § 97.411(a)(1), which allocation is terminated for such control period pursuant to § 97.411(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR NO_X Annual units under § 97.411(c)(1)(ii) whose allocation of an amount of TR NO_X Annual allowances for such control period in the notice of data availability issued under § 97.411(b)(1)(ii)(B) is covered by § 97.411(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR NO_X Annual allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.410(a) and will be allocated additional TR NO_X Annual allowances (if any) in accordance with §§ 97.411(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR NO_X Annual unit described in paragraph (a)(1) of this section, an allocation of TR NO_X Annual allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR NO_X Annual unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR NO_X Annual unit operates in the State after operating in another jurisdiction and for which

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the unit is not already allocated one or more TR NO_X Annual allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR NO_X annual unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO_X Annual allowances determined for all such TR NO_X Annual units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR NO_X Annual allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances determined for each such TR NO_X Annual unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR NO_X Annual allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR NO_X Annual unit the amount of the TR NO_X Annual allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR NO_X Annual allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.411(b)(1)(i) and (ii), of the amount of TR NO_X Annual allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR NO_X Annual unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR NO_X Annual allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR NO_X Annual allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR NO_X Annual allowances referenced in the notice of data availability required under § 97.411(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR NO_X Annual allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances determined for each such TR NO_X Annual unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO_X Annual allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR NO_X Annual unit the amount of the TR NO_X Annual allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO_X Annual allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR NO_X Annual allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR NO_X Annual unit that is in the State, is allocated an amount of TR NO_X Annual allowances in the notice of data availability issued under § 97.411(a)(1), and continues to be allocated TR NO_X Annual allowances for such control period in accordance with § 97.411(a)(2), an amount of TR NO_X Annual allowances equal to the following: the total amount of such remaining unallocated TR NO_X Annual allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.411(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Annual trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.411(b)(1)(iii), (iv), and (v), of the amount of TR NO_X Annual allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR NO_X Annual unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NO_X Annual units in descending order based on the amount of such units' allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR NO_X Annual allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR NO_X Annual units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's

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allocation under paragraph (a)(10) of this section by one TR NO_X Annual allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR NO_X Annual units located in Indian country within the borders of each State, the Administrator will allocate TR NO_X Annual allowances to the TR NO_X Annual units as follows:

(1) The TR NO_X Annual allowances will be allocated to the following TR NO_X Annual units, except as provided in paragraph (b)(10) of this section:

(i) TR NO_X Annual units that are not allocated an amount of TR NO_X Annual allowances in the notice of data availability issued under § 97.411(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR NO_X Annual units under § 97.411(c)(1)(ii) whose allocation of an amount of TR NO_X Annual allowances for such control period in the notice of data availability issued under § 97.411(b)(2)(ii)(B) is covered by § 97.411(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR NO_X Annual allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.410(a) and will be allocated additional TR NO_X Annual allowances (if any) in accordance with § 97.411(c)(5).

(3) The Administrator will determine, for each TR NO_X Annual unit described in paragraph (b)(1) of this section, an allocation of TR NO_X Annual allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR NO_X Annual unit commences commercial operation.

(4)(i) The allocation to each TR NO_X annual unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO_X Annual allowances determined for all such TR NO_X Annual units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR NO_X Annual allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances determined for each such TR NO_X Annual unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR NO_X Annual allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR NO_X Annual unit the amount of the TR NO_X Annual allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR NO_X Annual allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.411(b)(2)(i) and (ii), of the amount of TR NO_X Annual allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR NO_X Annual unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR NO_X Annual allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR NO_X Annual allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR NO_X Annual allowances referenced in the notice of data availability required under § 97.411(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR NO_X Annual allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances determined for each such TR NO_X Annual unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO_X Annual allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR NO_X Annual unit the amount of the TR NO_X Annual allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO_X Annual allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR NO_X Annual allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR NO_X Annual allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.38(a)(4) or (5) covering such control period, include such unallocated TR NO_X Annual allowances in the portion of the State NO_X Annual trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.411(b)(2)(iii), (iv), and (v), of the amount of TR NO_X Annual allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each TR NO_X Annual unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (9)(iv) of this section, or paragraphs (b)(6), 9(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations

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under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NO_X Annual units in descending order based on the amount of such units' allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR NO_X Annual allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR NO_X Annual units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one TR NO_X Annual allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.413 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.415, each TR NO_X Annual source, including all TR NO_X Annual units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Annual Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Annual unit at the source in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.415, each TR NO_X Annual source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.402, and §§ 97.414 through 97.418, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.414 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.418 concerning delegation of authority to make submissions, each submission under the TR NO_X Annual Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Annual source and TR NO_X Annual unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a TR NO_X Annual source or a TR NO_X Annual unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.418.

§ 97.415 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any

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time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a TR NO_X Annual source or a TR NO_X Annual unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.416, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Annual source or a TR NO_X Annual unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.416 amending the list of owners and operators to reflect the change.

(d) *Changes in units at the source.* Within 30 days of any change in which units are located at a TR NO_X Annual source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.416 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.416 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Annual source, and each TR NO_X Annual unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Annual source and of each TR NO_X Annual unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Annual unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each TR NO_X Annual unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Annual unit, or where a utility or industrial customer purchases power from a TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Annual unit at the source; and TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Annual allowances by contract, TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.417 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.416 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.416 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

§ 97.418 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d) shall be deemed to be an electronic submission by me.''

(ii) ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.418 is terminated.''.

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.419 [Reserved]

§ 97.420 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.416, the Administrator will establish a compliance account for the TR NO_X Annual source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.425(b)(3).

(c) *General accounts.* (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Annual allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NO_X Annual allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.''

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a

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general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Annual allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Annual allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Annual allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Annual allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO_X Annual allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator

provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(c)(5)(iv) shall be deemed to be an electronic submission by me.''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.420(c)(5) is terminated.''.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Annual allowance transfer under § 97.422 for any TR NO_X Annual allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Annual allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Annual allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted TR NO_X Annual allowance transfer under § 97.422 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Annual allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.414(a) and 97.418 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 97.421 Recordation of TR NO_X Annual allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of § 52.38(a)(3)(i) through (iv) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR NO_X Annual source's compliance account the TR

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NO_X Annual allowances allocated to the TR NO_X Annual units at the source, or in each appropriate Allowance Management System account the TR NO_X Annual allowances auctioned to TR NO_X Annual units, in accordance with § 97.411(a), or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source, or in each appropriate Allowance Management System account the TR NO_X Annual allowances auctioned to TR NO_X Annual units, in accordance with § 97.411(a), or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source, or in each appropriate Allowance Management System account the TR NO_X Annual allowances auctioned to TR NO_X Annual units, in accordance with § 97.411(a), or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source, or in each appropriate Allowance Management System account the TR NO_X Annual allowances auctioned to TR NO_X Annual units, in accordance with § 97.411(a), or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source, or in each appropriate Allowance Management System account the TR NO_X Annual allowances auctioned to TR NO_X Annual units, in accordance with § 97.412(a)(2) through (8) and (12), or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.412(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2013 and February 15 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated to the TR NO_X Annual units at the source in accordance with § 97.412(a)(9) through (12), for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (i) of this section, of TR NO_X Annual allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.411 or § 97.412 or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR NO_X Annual allowances to a TR NO_X Annual unit or other entity in an Allowance Management System account, the Administrator will assign each TR NO_X Annual allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Annual allowance is allocated or auctioned.

§ 97.422 Submission of TR NO_X Annual allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Annual allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Annual allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Annual allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Annual allowance identified by serial number in the transfer.

§ 97.423 Recordation of TR NO_X Annual allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Annual allowance transfer that is correctly submitted under § 97.422, the Administrator will record a TR NO_X Annual allowance transfer by moving each TR NO_X Annual allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR NO_X Annual allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Annual allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 97.424 for the control period immediately before such allowance transfer deadline.

(c) Where a TR NO_X Annual allowance transfer is not correctly submitted under § 97.422, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Annual allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Annual allowance transfer that is not correctly submitted under § 97.422, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.424 Compliance with TR NO_X Annual emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Annual allowances are available to be deducted for compliance with a source's TR NO_X Annual emissions limitation for a control period in a given year only if the TR NO_X Annual allowances:

(1) Were allocated for such control period or a control period in a prior year; and

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(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account TR NO_X Annual allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NO_X Annual emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Annual allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Annual units at the source for such control period; or

(2) If there are insufficient TR NO_X Annual allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Annual allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Annual allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Annual allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Annual source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Annual allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Annual allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR NO_X Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Annual source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Annual allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.425 Compliance with TR NO_X Annual assurance provisions.

(a) *Availability for deduction.* TR NO_X Annual allowances are available to be deducted for compliance with the TR NO_X Annual assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR NO_X Annual sources and units in a State (and Indian country within the borders of such State) only if the TR NO_X Annual allowances:

(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR NO_X Annual sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Annual allowances available under paragraph (a) of this section for compliance with the TR NO_X Annual assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2013 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO_X emissions exceed the State assurance level as described in § 97.406(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions from each TR NO_X Annual source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR NO_X Annual units with total NO_X emissions exceeding the State assurance level for a control period in a given year, as described in § 97.406(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR NO_X Annual source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR NO_X Annual unit (if any) at the source that operates during, but is not allocated an amount of TR NO_X Annual allowances for, such control period, the unit's allowable NO_X emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more TR NO_X Annual sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of TR NO_X Annual allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in §97.406(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice

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and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with § 97.406(c)(2)(iii), §§ 97.406(b) and 97.430 through 97.435, the definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share'' in § 97.402, and the calculation formula in § 97.406(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR NO_X Annual units with total NO_X emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR NO_X Annual sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR NO_X Annual allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for the them and for the appropriate TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR NO_X Annual allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR NO_X Annual allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NO_X Annual allowances that the owners and operators are required to hold in accordance with § 97.406(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for such control period with regard to the TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR NO_X Annual source and TR NO_X Annual unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for such control period with regard to the TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR NO_X Annual allowances that the owners and operators are required to hold for such control period with regard to the TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR NO_X Annual allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR NO_X Annual allowances in the assurance account established by the Administrator for the appropriate TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each

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TR NO_X Annual allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR NO_X Annual allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR NO_X Annual allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate at TR NO_X Annual sources, TR NO_X Annual units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR NO_X Annual allowances held in such assurance account equal to the amount of the decrease. If TR NO_X Annual allowances were transferred to such assurance account from more than one account, the amount of TR NO_X Annual allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of TR NO_X Annual allowances transferred to such assurance account for such control period from such transferor account.

(C) Each TR NO_X Annual allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the TR NO_X Annual assurance provisions for such control period must be a TR NO_X Annual allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

§ 97.426 Banking.

(a) A TR NO_X Annual allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Annual allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Annual allowance is deducted or transferred under § 97.411(c), § 97.423, § 97.424, § 97.425, 97.427, or 97.428.

§ 97.427 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.428 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Annual Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Annual allowances from or transfer TR NO_X Annual allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.429 [Reserved]

§ 97.430 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Annual unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.402 and in § 72.2 of this chapter shall apply, the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''TR NO_X Annual unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively as defined in § 97.402, and the term ''newly affected unit'' shall be deemed to mean ''newly affected TR NO_X Annual unit''. The owner or operator of a unit that is not a TR NO_X Annual unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Annual unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Annual unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.431 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Annual unit that commences commercial operation before July 1, 2011, January 1, 2012;

(2) For the owner or operator of a TR NO_X Annual unit that commences commercial operation on or after July 1, 2011, the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation;

(3) The owner or operator of a TR NO_X Annual unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §§ 75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under § 97.430 through § 97.435, rather than the monitoring systems required under part 75 of this chapter;

(ii) NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.435, rather than § 75.66.

(c) *Reporting data.* The owner or operator of a TR NO_X Annual unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of

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this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Annual unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.435.

(2) No owner or operator of a TR NO_X Annual unit shall operate the unit so as to discharge, or allow to be discharged, NO_X to the atmosphere without accounting for all such NO_X in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NO_X Annual unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR NO_X Annual unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.405 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.431(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Annual unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.431 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Annual unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.430(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.430(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.435 to determine whether the approval applies under the TR NO_X Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Annual unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.430(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.430(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.430(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.430(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.430(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under § 97.430(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.433.

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(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Annual Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NO_X Annual Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.432(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.432 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.431 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or

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recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.431 for each disapproved monitoring system.

§ 97.433 Notifications concerning monitoring.

The designated representative of a TR NO_X Annual unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.434 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.414(a).

(b) *Monitoring plans.* The owner or operator of a TR NO_X Annual unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.431, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the NO_X mass emissions data and heat input data for the TR NO_X Annual unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.430(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For TR NO_X Annual units that are also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions.

§ 97.435 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Annual unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.430 through 97.434.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

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(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

■ 75. Part 97 is amended by adding subpart BBBBB to read as follows:

Subpart BBBBB—TR NO_X Ozone Season Trading Program

Subpart BBBBB—TR NO_X Ozone Season Trading Program

§ 97.501 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 52.38 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to TR NO_X Ozone Season allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(3), (4), or (5) of this chapter, of the amount of such TR NO_X Ozone Season allowances to be initially credited, at no cost to the recipient, to:

(1) A TR NO_X Ozone Season unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a TR NO_X Ozone Season unit qualifying for an initial credit, a credit in the amount of zero TR NO_X Ozone Season allowances, the TR NO_X Ozone Season unit will be treated as being allocated an amount (*i.e.,* zero) of TR NO_X Ozone Season allowances.

Allowable NO_X emission rate means, for a unit, the most stringent State or federal NO_X emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit's heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Ozone Season allowances under the TR NO_X Ozone Season Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Ozone Season allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Ozone Season allowance transfer must be submitted for recordation in a TR NO_X Ozone Season source's compliance account in order to be available for use in complying with the source's TR NO_X Ozone Season emissions limitation for such control period in accordance with §§ 97.506 and 97.524.

Alternate designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.525(b)(3) for certain owners and operators of a group of one or more TR NO_X Ozone Season sources and units in a given State (and Indian country within the borders of such State), in which are held TR NO_X Ozone Season allowances available for use for a control period in a given year in complying with the TR NO_X Ozone

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Season assurance provisions in accordance with §§ 97.506 and 97.525.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Ozone Season allowances held in the general account and, for a TR NO_X Ozone Season source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means ''coal'' as defined in § 72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.505.

(i) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.505, for a unit that is not a TR NO_X Ozone Season unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Ozone Season unit under § 97.504.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition

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and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§ 97.513(a) and 97.515(a) as the designated representative for a group of one or more TR NO_X Ozone Season sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii), the common designated representative's share of the State NO_X Ozone Season trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Ozone Season units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NO_X emissions during such control period from a group of one or more TR NO_X Ozone Season units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NO_X Ozone Season trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR NO_X Ozone Season allowances allocated for such control period to a group of one or more TR NO_X Ozone Season units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR NO_X Ozone Season allowances purchased by an owner or operator of such TR NO_X Ozone Season units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR NO_X Ozone Season units in accordance with the TR NO_X Ozone Season allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(4) or (5) of this chapter, multiplied by the sum of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's variability limit under § 97.510(b) for such control period and divided by such State NO_X Ozone Season trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR NO_X Ozone Season allowances allocated under §§ 97.511 and 97.512 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Ozone Season allowances for such control period equal to the unit's allowable NO_X emission rate applicable to such control period, multiplied by a capacity factor of 0.92 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.32 (if the unit is a simple combustion turbine during such control period), 0.71 (if the unit is a combined cycle turbine during such control period), 0.73 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.44 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Ozone Season source under this subpart, in which any TR NO_X Ozone Season allowance allocations to the TR NO_X Ozone Season units at the source are recorded and in which are held any TR NO_X Ozone Season allowances available for use for a control period in a given year in complying with the source's TR NO_X Ozone Season emissions limitation in accordance with §§ 97.506 and 97.524.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.530 through 97.535. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting May 1 of a calendar year, except as provided in § 97.506(c)(3), and

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ending on September 30 of the same year, inclusive.

Designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source during a control period in a given year that exceeds the TR NO_X Ozone Season emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on ''average annual fuel consumption of fossil fuel'' in §§ 97.504(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means ''natural gas'' as defined in § 72.2 of this chapter.

Newly affected TR NO_X Ozone Season unit means a unit that was not a TR NO_X Ozone Season unit when it began operating but that thereafter becomes a TR NO_X Ozone Season unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at a source respectively, any person who operates, controls, or supervises a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit;

(2) Any holder of a leasehold interest in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR NO_X Ozone Season unit; and

(3) Any purchaser of power from a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is

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unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means ''permitting authority'' as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit, 33 percent of the unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to TR NO_X Ozone Season allowances, the moving of TR NO_X Ozone Season allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Ozone Season allowance, the unique identification number assigned to each TR NO_X Ozone Season allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR NO_X Ozone Season Trading Program pursuant to § 52.38(b) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

LHV = HHV ¥ 10.55 (W + 9H)

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(3), (4), or (5) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR NO_X Ozone Season Trading Program.

TR NO_X Ozone Season allowance deduction or deduct TR NO_X Ozone Season allowances means the permanent withdrawal of TR NO_X Ozone Season allowances by the Administrator from a compliance account (*e.g.*, in order to account for compliance with the TR NO_X Ozone Season emissions limitation) or from an assurance account (*e.g.*, in order to account for compliance with the assurance provisions under §§ 97.506 and 97.525).

TR NO_X Ozone Season allowances held or hold TR NO_X Ozone Season allowances means the TR NO_X Ozone Season allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart.

TR NO_X Ozone Season emissions limitation means, for a TR NO_X Ozone Season source, the tonnage of NO_X emissions authorized in a control period in a given year by the TR NO_X Ozone Season allowances available for deduction for the source under § 97.524(a) for such control period.

TR NO_X Ozone Season source means a source that includes one or more TR NO_X Ozone Season units.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with this subpart and § 52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

TR NO_X Ozone Season unit means a unit that is subject to the TR NO_X Ozone Season Trading Program.

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TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and 52.39(a), (b), (d) through (f), (j), and (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and 52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.503 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour lb—
pound mmBtu—million
Btu MWe—megawatt
electrical MWh—megawatt
hour NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million scfh—
standard cubic feet per hour SO_2—
sulfur dioxide
yr—year

§ 97.504 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR NO_X Ozone Season units, and any source that includes one or more such units shall be a TR NO_X Ozone Season source, subject to the requirements of this subpart: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Ozone Season unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Ozone Season unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR NO_X Ozone Season unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR NO_X Ozone Season unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR NO_X Ozone Season unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a TR NO_X Ozone Season unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR NO_X Ozone Season unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR NOX Ozone Season unit.

(c) A certifying official of an owner or operator of any unit or other equipment

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may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, of the TR NO_X Ozone Season Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: ''I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) Response. The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Ozone Season Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.505 Retired unit exemption.

(a)(1) Any TR NO_X Ozone Season unit that is permanently retired shall be exempt from § 97.506(b) and (c)(1), § 97.524, and §§ 97.530 through 97.535.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Ozone Season unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.506 Standard requirements.

(a) *Designated representative requirements*. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.513 through 97.518.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.530 through 97.535.

(2) The emissions data determined in accordance with §§ 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements. (1) TR NO_X Ozone Season emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under § 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii) If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under § 97.524(d); and

(B) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions. (i) If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated

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representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under § 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.525(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's variability limit under § 97.510(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season units at TR NO_X Ozone Season sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR NO_X Ozone Season allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods. A TR NO_X Ozone Season unit shall be subject to the requirements under paragraphs (c)(1) and (c)(2) of this section for the control period starting on the later of May 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NO_X Ozone Season Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Ozone Season allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.530 through 97.535 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.516 for the designated representative for the source and each TR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.516 changing the designated representative.

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(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Trading Program.

(2) The designated representative of a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall make all submissions required under the TR NO_X Ozone Season Trading Program, except as provided in § 97.518. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(2) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR NO_X Ozone Season Trading Program or exemption under § 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season source or TR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.507 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NO_X Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NO_X Ozone Season Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.508 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Ozone Season Trading Program are set forth in part 78 of this chapter.

§ 97.509 [Reserved]

§ 97.510 State NO_X Ozone Season trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State NO_X Ozone Season trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR NO_X Ozone Season allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X Ozone Season trading budget (tons) * for 2012 and 2013	New unit set-aside (tons) for 2012 and 2013	Indian country new unit set-aside (tons) for 2012 and 2013
Alabama	31,746	635	
Arkansas	15,037	301	
Florida	27,825	529	28
Georgia	27,944	559	
Illinois	21,208	1,697	
Indiana	46,876	1,406	
Kentucky	36,167	1,447	
Louisiana	13,432	390	13
Maryland	7,179	144	
Mississippi	10,160	193	10
New Jersey	3,382	68	
New York	8,331	242	8
North Carolina	22,168	1,308	22
Ohio	40,063	801	
Pennsylvania	52,201	1,044	
South Carolina	13,909	264	14
Tennessee	14,908	298	
Texas	63,043	1,828	63
Virginia	14,452	723	
West Virginia	25,283	1,264	

State	NO_X Ozone Season trading budget (tons) * for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
Alabama	31,499	630	
Arkansas	15,037	301	
Florida	27,825	529	28
Georgia	18,279	366	
Illinois	21,208	1,697	
Indiana	46,175	1,385	
Kentucky	32,674	1,307	
Louisiana	13,432	390	13
Maryland	7,179	144	
Mississippi	10,160	193	10
New Jersey	3,382	68	

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State	NO_X Ozone Season trading budget (tons) * for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
New York	8,331	242	8
North Carolina	18,455	1,089	18
Ohio	37,792	756	
Pennsylvania	51,912	1,038	
South Carolina	13,909	264	14
Tennessee	8,016	160	
Texas	63,043	1,828	63
Virginia	14,452	723	
West Virginia	23,291	1,165	

* Each trading budget includes the new unit set-aside and, where applicable, the Indian country new unit set-aside and does not include the variability limit.

(b) The States' variability limits for the State NO_X Ozone Season trading budgets for the control periods in 2012 and thereafter are as follows:

State	Variability limits for 2012 and 2013	Variability limits for 2014 and thereafter
Alabama	6,667	6,615
Arkansas	3,158	3,158
Florida	5,843	5,843
Georgia	5,868	3,839
Illinois	4,454	4,454
Indiana	9,844	9,697
Kentucky	7,595	6,862
Louisiana	2,821	2,821
Maryland	1,508	1,508
Mississippi	2,134	2,134
New Jersey	710	710
New York	1,750	1,750
North Carolina	4,655	3,876
Ohio	8,413	7,936
Pennsylvania	10,962	10,902
South Carolina	2,921	2,921
Tennessee	3,131	1,683
Texas	13,239	13,239
Virginia	3,035	3,035
West Virginia	5,309	4,891

§ 97.511 Timing requirements for TR NO_X Ozone Season allowance allocations.

(a) *Existing units.* (1) TR NO_X Ozone Season allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR NO_X Ozone Season unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR NO_X Ozone Season unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR NO_X Ozone Season allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR NO_X Ozone Season allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Ozone Season allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.*—(1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO_X Ozone Season allowance allocation to each TR NO_X Ozone Season unit in a State, in accordance with § 97.512(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO_X Ozone Season units) are in accordance with § 97.512(a)(2) through (7) and (12) and §§ 97.506(b)(2) and 97.530 through 97.535.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice

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of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.512(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR NO_X Ozone Season allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any TR NO_X Ozone Season units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO_X Ozone Season units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR NO_X Ozone Season units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO_X Ozone Season units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR NO_X Ozone Season allowance allocation to each TR NO_X Ozone Season unit in accordance with § 97.512(a)(9), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO_X Ozone Season units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO_X Ozone Season allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO_X Ozone Season allowances in accordance with § 97.512(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO_X Ozone Season allowance allocation to each TR NO_X Ozone Season unit in Indian country within the borders of a State, in accordance with § 97.512(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO_X Ozone Season units) are in accordance with § 97.512(b)(2) through (7) and (12) and §§ 97.506(b)(2) and 97.530 through 97.535.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.512(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR NO_X Ozone Season allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any TR NO_X Ozone Season units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO_X Ozone Season units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR NO_X Ozone Season units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO_X Ozone Season units in the each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR NO_X Ozone Season allowance allocation to each TR NO_X Ozone Season unit in accordance with § 97.512(b)(9), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO_X Ozone Season units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations. (v) To the extent any TR NO_X Ozone Season allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO_X Ozone Season allowances in accordance with § 97.512(b)(10).

(c) Units incorrectly allocated TR NO_X Ozone Season allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Ozone Season allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.512(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, where such control period and the recipient are covered by the

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provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1, 2012 and is allocated TR NO_X Ozone Season allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO_X Ozone Season unit as of May 1, 2012 and is allocated TR NO_X Ozone Season allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO_X Ozone Season units as of May 1, 2012; or

(B) The recipient is not located as of May 1 of the control period in the State from whose NO_X Ozone Season trading budget the TR NO_X Ozone Season allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1 of such control period and is allocated TR NO_X Ozone Season allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO_X Ozone Season unit as of January 1 of such control period and is allocated TR NO_X Ozone Season allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO_X Ozone Season units as of May 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR NO_X Ozone Season allowances under § 97.521.

(3) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Ozone Season allowances were recorded an amount of TR NO_X Ozone Season allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Ozone Season allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Ozone Season allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Ozone Season allowances.

(5)(i) With regard to the TR NO_X Ozone Season allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR NO_X Ozone Season allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season trading budget the TR NO_X Ozone Season allowances were allocated; or

(B) If the State has a SIP revision approved under § 52.38(b)(4) or (5) covering such control period, include such TR NO_X Annual allowances in the portion of the State NO_X Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR NO_X Ozone Season allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR NO_X Ozone Season allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under § 52.38(b)(4) or (5) covering such control period, include such TR NO_X Ozone Season allowances in the portion of the State NO_X Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR NO_X Ozone Season allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR NO_X Ozone Season allowances to the Indian country new unit set-aside for such control period.

§ 97.512 TR NO_X Ozone Season allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR NO_X Ozone Season units in each State, the Administrator will allocate TR NO_X Ozone Season allowances to the TR NO_X Ozone Season units as follows:

(1) The TR NO_X Ozone Season allowances will be allocated to the following TR NO_X Ozone Season units, except as provided in paragraph (a)(10) of this section:

(i) TR NO_X Ozone Season units that are not allocated an amount of TR NO_X Ozone Season allowances in the notice of data availability issued under § 97.511(a)(1);

(ii) TR NO_X Ozone Season units whose allocation of an amount of TR NO_X Ozone Season allowances for such control period in the notice of data availability issued under § 97.511(a)(1) is covered by § 97.511(c)(2) or (3);

(iii) TR NO_X Ozone Season units that are allocated an amount of TR NO_X Ozone Season allowances for such control period in the notice of data availability issued under § 97.511(a)(1), which allocation is terminated for such control period pursuant to § 97.511(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR NO_X Ozone Season units under § 97.511(c)(1)(ii) whose allocation of an amount of TR NO_X Ozone Season allowances for such control period in the notice of data availability issued under § 97.511(b)(1)(ii)(B) is covered by § 97.511(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR NO_X Ozone Season allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.510(a) and will be allocated additional TR NO_X Ozone Season allowances (if any) in accordance with §§ 97.511(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR NO_X Ozone Season unit described in paragraph (a)(1) of this section, an allocation of TR NO_X Ozone Season allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR NO_X

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Ozone Season unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR NO_X Ozone Season unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR NO_X Ozone Season allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR NO_X Ozone Season unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO_X Ozone Season allowances determined for all such TR NO_X Ozone Season units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances determined for each such TR NO_X Ozone Season unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR NO_X Ozone Season unit the amount of the TR NO_X Ozone Season allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(i) and (ii), of the amount of TR NO_X Ozone Season allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR NO_X Ozone Season unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR NO_X Ozone Season allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR NO_X Ozone Season allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR NO_X Ozone Season allowances referenced in the notice of data availability required under § 97.511(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR NO_X Ozone Season allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances determined for each such TR NO_X Ozone Season unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO_X Ozone Season allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR NO_X Ozone Season unit the amount of the TR NO_X Ozone Season allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO_X Ozone Season allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR NO_X Ozone Season allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR NO_X Ozone Season unit that is in the State, is allocated an amount of TR NO_X Ozone Season allowances in the notice of data availability issued under § 97.511(a)(1), and continues to be allocated TR NO_X Ozone Season allowances for such control period in accordance with § 97.511(a)(2), an amount of TR NO_X Ozone Season allowances equal to the following: the total amount of such remaining unallocated TR NO_X Ozone Season allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.511(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(iii), (iv), and (v), of the amount of TR NO_X Ozone Season allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR NO_X Ozone Season unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NO_X Ozone Season units in descending order based on the amount of such units' allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR NO_X Ozone Season allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in a total

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allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR NO_X Ozone Season units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (a)(10) of this section by one TR NO_X Ozone Season allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR NO_X Ozone Season units located in Indian country within the borders of each State, the Administrator will allocate TR NO_X Ozone Season allowances to the TR NO_X Ozone Season units as follows:

(1) The TR NO_X Ozone Season allowances will be allocated to the following TR NO_X Ozone Season units, except as provided in paragraph (b)(10) of this section:

(i) TR NO_X Ozone Season units that are not allocated an amount of TR NO_X Ozone Season allowances in the notice of data availability issued under § 97.511(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR NO_X Ozone Season units under § 97.511(c)(1)(ii) whose allocation of an amount of TR NO_X Ozone Season allowances for such control period in the notice of data availability issued under § 97.511(b)(2)(ii)(B) is covered by § 97.511(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR NO_X Ozone Season allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.510(a) and will be allocated additional TR NO_X Ozone Season allowances (if any) in accordance with § 97.511(c)(5).

(3) The Administrator will determine, for each TR NO_X Ozone Season unit described in paragraph (b)(1) of this section, an allocation of TR NO_X Ozone Season allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR NO_X Ozone Season unit commences commercial operation.

(4)(i) The allocation to each TR NO_X Ozone Season unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO_X Ozone Season allowances determined for all such TR NO_X Ozone Season units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR NO_X Ozone Season allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances determined for each such TR NO_X Ozone Season unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR NO_X Ozone Season allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR NO_X Ozone Season unit the amount of the TR NO_X Ozone Season allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR NO_X Ozone Season allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(2)(i) and (ii), of the amount of TR NO_X Ozone Season allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR NO_X Ozone Season unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR NO_X Ozone Season allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR NO_X Ozone Season allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR NO_X Ozone Season allowances referenced in the notice of data availability required under § 97.511(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR NO_X Ozone Season allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances determined for each such TR NO_X Ozone Season unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO_X Ozone Season allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR NO_X Ozone Season unit the amount of the TR NO_X Ozone Season allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO_X Ozone Season allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR NO_X Ozone Season allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR NO_X Ozone Season allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.38(b)(4) or (5) covering such control period, include such unallocated TR NO_X Ozone Season allowances in the portion of the State NO_X Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.

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(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(2)(iii), (iv), and (v), of the amount of TR NO_X Ozone Season allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each TR NO_X Ozone Season unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (9)(iv) of this section, or paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NO_X Ozone Season units in descending order based on the amount of such units' allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR NO_X Ozone Season allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR NO_X Ozone Season units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one TR NO_X Ozone Season allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.513 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.515, each TR NO_X Ozone Season source, including all TR NO_X Ozone Season units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Ozone Season Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Ozone Season unit at the source in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.515, each TR NO_X Ozone Season source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.502, and §§ 97.514 through 97.518, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.514 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.518 concerning delegation of authority to make submissions, each submission under the TR NO_X Ozone Season Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Ozone Season source and TR NO_X Ozone Season unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit only if the

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submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.518.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.516, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.516 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR NO_X Ozone Season source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.516 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.516 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Ozone Season source, and each TR NO_X Ozone Season unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Ozone Season source and of each TR NO_X Ozone Season unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Ozone Season unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season Trading Program on behalf of the owners and operators of the source and of each TR NO_X Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Ozone Season unit, or where a utility or industrial customer purchases power from a TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Ozone Season unit at the source; and TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Ozone Season allowances by contract, TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

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(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.517 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.516 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.516 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

§ 97.518 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d) shall be deemed to be an electronic submission by me.''

(ii) ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.518 is terminated.''.

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.519 [Reserved]

§ 97.520 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.516, the Administrator will establish a compliance account for the TR NO_X Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.525(b)(3).

(c) *General accounts.* (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Ozone Season allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to

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represent their ownership interest with respect to the TR NO_X Ozone Season allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.''

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Ozone Season allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv) shall be deemed to be an electronic submission by me.''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.520(c)(5) is terminated.''.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Ozone Season allowance transfer under § 97.522 for any TR NO_X Ozone Season allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Ozone Season allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Ozone Season allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted TR NO_X Ozone Season allowance transfer under § 97.522 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Ozone Season allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.514(a) and 97.518 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 97.521 Recordation of TR NO_X Ozone Season allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the

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requirements of § 52.38(b)(3)(i) through (iv) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO_X Ozone Season allowances auctioned to TR NO_X Ozone Season units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO_X Ozone Season allowances auctioned to TR NO_X Ozone Season units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO_X Ozone Season allowances auctioned to TR NO_X Ozone Season units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO_X Ozone Season allowances auctioned to TR NO_X Ozone Season units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO_X Ozone Season allowances auctioned to TR NO_X Ozone Season units, in accordance with § 97.512(a)(2) through (8) and (12), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.512(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By November 15, 2012 and November 15 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season units at the source in accordance with § 97.512(a)(9) through (12), for the control period in the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (i) of this section, of TR NO_X Ozone Season allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.511 or § 97.512 or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR NO_X Ozone Season allowances to a TR NO_X Ozone Season unit or other entity in an Allowance Management System account, the Administrator will assign each TR NO_X Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Ozone Season allowance is allocated or auctioned.

§ 97.522 Submission of TR NO_X Ozone Season allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Ozone Season allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Ozone Season allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Ozone Season allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Ozone Season allowance identified by serial number in the transfer.

§ 97.523 Recordation of TR NO_X Ozone Season allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Ozone Season allowance transfer that is correctly submitted under § 97.522, the Administrator will record a TR NO_X Ozone Season allowance transfer by moving each TR NO_X Ozone Season allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR NO_X Ozone Season allowance transfer to or from a

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compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 97.524 for the control period immediately before such allowance transfer deadline.

(c) Where a TR NO_X Ozone Season allowance transfer is not correctly submitted under § 97.522, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Ozone Season allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Ozone Season allowance transfer that is not correctly submitted under § 97.522, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.524 Compliance with TR NO_X Ozone Season emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Ozone Season allowances are available to be deducted for compliance with a source's TR NO_X Ozone Season emissions limitation for a control period in a given year only if the TR NO_X Ozone Season allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account TR NO_X Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NO_X Ozone Season emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Ozone Season allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Ozone Season units at the source for such control period; or

(2) If there are insufficient TR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Ozone Season allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Ozone Season source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Ozone Season allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Ozone Season allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR NO_X Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Ozone Season source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Ozone Season allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.525 Compliance with TR NO_X Ozone Season assurance provisions.

(a) *Availability for deduction.* TR NO_X Ozone Season allowances are available to be deducted for compliance with the TR NO_X Ozone Season assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR NO_X Ozone Season sources and units in a State (and Indian country within the borders of such State) only if the TR NO_X Ozone Season allowances:

(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR NO_X Ozone Season sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Ozone Season allowances available under paragraph (a) of this section for compliance with the TR NO_X Ozone Season assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2013 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO_X emissions exceed the State assurance level as described in § 97.506(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions from each TR NO_X Ozone Season source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR NO_X Ozone Season units with total NO_X emissions exceeding the State assurance level for a control

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period in a given year, as described in § 97.506(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR NO_X Ozone Season source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR NO_X Ozone Season unit (if any) at the source that operates during, but is not allocated an amount of TR NO_X Ozone Season allowances for, such control period, the unit's allowable NO_X emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more TR NO_X Ozone Season sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of TR NO_X Ozone Season allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in § 97.506(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with § 97.506(c)(2)(iii), §§ 97.506(b) and 97.530 through 97.535, the definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share'' in § 97.502, and the calculation formula in § 97.506(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR NO_X Ozone Season units with total NO_X emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR NO_X Ozone Season sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR NO_X Ozone Season allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for the them and for the appropriate TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR NO_X Ozone Season allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR NO_X Ozone Season allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NO_X Ozone Season allowances that the owners and operators are required to hold in accordance with § 97.506(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for such control period with regard to the TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR NO_X Ozone Season source and TR NO_X Ozone Season unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for such control period with regard to the TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR NO_X Ozone Season allowances that the owners and operators are required to hold for such control period with regard to the TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR NO_X Ozone Season allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR NO_X Ozone Season allowances in the assurance account established by the Administrator for the appropriate TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO_X Ozone Season allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR NO_X Ozone Season allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR NO_X Ozone Season allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate at TR NO_X Ozone Season sources, TR NO_X Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR NO_X Ozone Season allowances held in such assurance account equal to the amount of the decrease. If TR NO_X Ozone Season allowances were transferred to such assurance account from more than one account, the amount of TR NO_X Ozone Season allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of TR NO_X Ozone Season allowances transferred to such assurance account for such control period from such transferor account.

(C) Each TR NO_X Ozone Season allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the TR NO_X Ozone Season assurance provisions for such control period must be a TR NO_X Ozone Season allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

§ 97.526 Banking.

(a) A TR NO_X Ozone Season allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Ozone Season allowance is deducted or transferred under § 97.511(c), § 97.523, § 97.524, § 97.525, § 97.527, or § 97.528.

§ 97.527 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.528 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Ozone Season Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Ozone Season allowances from or transfer TR NO_X Ozone Season allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.502 and in § 72.2 of this chapter shall apply, the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''TR NO_X Ozone Season unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively as defined in § 97.502, and the term ''newly affected unit'' shall be deemed to mean ''newly affected TR NO_X Ozone Season unit''. The owner or operator of a unit that is not a TR NO_X Ozone Season unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Ozone Season unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.531 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

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(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation before July 1, 2011, May 1, 2012.

(2) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on an annual basis under § 97.534(d), by the later of the following:

(i) 180 calendar days after the date on which the unit commences commercial operation; or

(ii) May 1, 2012.

(3) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on a control period basis under § 97.534(d)(2)(ii), by the following date:

(i) 180 calendar days after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(3)(i) of this section.

(4) The owner or operator of a TR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), or (3) of this section shall meet the requirements of §§ 75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under § 97.530 through § 97.535, rather than the monitoring systems required under part 75 of this chapter;

(ii) NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.535, rather than § 75.66.

(c) *Reporting data.* The owner or operator of a TR NO_X Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.535.

(2) No owner or operator of a TR NO_X Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NO_X to the atmosphere without accounting for all such NO_X in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NO_X Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR NO_X Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.505 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.531(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Ozone Season unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.531 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.530(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.530(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.535 to determine whether the approval applies under the TR NO_X Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.530(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

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(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.530(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.530(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.530(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.530(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under § 97.530(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words ''certification'' and ''initial certification'' are replaced by the word ''recertification'' and the word ''certified'' is replaced by with the word ''recertified''.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.533.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Ozone Season Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NO_X Ozone Season Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.532(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and

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2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.532 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.531 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.531 for each disapproved monitoring system.

§ 97.533 Notifications concerning monitoring.

The designated representative of a TR NO_X Ozone Season unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.534 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.514(a).

(b) *Monitoring plans.* The owner or operator of a TR NO_X Ozone Season unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.531, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) If the TR NO_X Ozone Season unit is subject to the Acid Rain Program or a TR NO_X Annual emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and shall report the NO_X mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that quarter is the third or fourth quarter of 2011 or the first quarter of 2012, in which case reporting shall commence in the quarter covering May 1, 2012 through June 30, 2012.

(2) If the TR NO_X Ozone Season unit is not subject to the Acid Rain Program or a TR NO_X Annual emissions limitation, then the designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in § 75.74(c) of this chapter) and report NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012; or

(B) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date.

(3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(4) For TR NO_X Ozone Season units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(5) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(6) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(3) of this section.

(e) *Compliance certification*. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Ozone Season unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.530 through 97.534.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis*: and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

76. Part 97 is amended by adding subpart CCCCC to read as follows:

Subpart CCCCC—TR SO_2 Group 1 Trading Program

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Subpart CCCCC—TR SO_2 Group 1 Trading Program

§ 97.601 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 1 Trading Program, under section 110 of the Clean Air Act and § 52.39 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

§ 97.602 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to TR SO_2 Group 1 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.39(d), (e), or (f) of this chapter, of the amount of such TR SO_2 Group 1 allowances to be initially credited, at no cost to the recipient, to:

(1) A TR SO_2 Group 1 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a TR SO_2 Group 1 unit qualifying for an initial credit, a credit in the amount of zero TR SO_2 Group 1 allowances, the TR SO_2 Group 1 unit will be treated as being allocated an amount (*i.e.,* zero) of TR SO_2 Group 1 allowances.

Allowable SO_2 emission rate means, for a unit, the most stringent State or federal SO_2 emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit's heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 1 allowances under the TR SO_2 Group 1 Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 1 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 emissions limitation for such control period in accordance with §§ 97.606 and 97.624.

Alternate designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.625(b)(3) for certain owners and operators of a group of one or more TR SO_2 Group 1 sources and units in a given State (and Indian country within the borders of such State), in which are held TR SO_2 Group 1 allowances available for use for a control period in a given year in complying with the TR SO_2 Group 1 assurance provisions in accordance with §§ 97.606 and 97.625.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 1 allowances held in the general account and, for a TR SO_2 Group 1 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

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(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq*.

Coal means ''coal'' as defined in § 72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.605.

(i) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.605, for a unit that is not a TR SO_2 Group 1 unit under § 97.604 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 1 unit under § 97.604.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§ 97.613(a) and 97.615(a) as the designated representative for a group of one or more TR SO_2 Group 1 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.606(c)(2)(iii), the common designated representative's share of the State SO_2 Group 1 trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of SO_2 emissions during such control period from a group of one or more TR SO_2 Group 1 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State SO_2 Group 1 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR SO_2 Group 1 allowances allocated for such control period to a group of one or more TR SO_2 Group 1 units located in the State (and Indian country within the borders of such

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State) and having the common designated representative for such control period and of the total amount of TR SO_2 Group 1 allowances purchased by an owner or operator of such TR SO_2 Group 1 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR SO_2 Group 1 units in accordance with the TR SO_2 Group 1 allowance auction provisions in a SIP revision approved by the Administrator under § 52.39(e) or (f) of this chapter, multiplied by the sum of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's variability limit under § 97.610(b) for such control period and divided by such State SO_2 Group 1 trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR SO_2 Group 1 allowances allocated under §§ 97.611 and 97.612 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 1 allowances for such control period equal to the unit's allowable SO_2 emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 1 source under this subpart, in which any TR SO_2 Group 1 allowance allocations to the TR SO_2 Group 1 units at the source are recorded and in which are held any TR SO_2 Group 1 allowances available for use for a control period in a given year in complying with the source's TR SO_2 Group 1 emissions limitation in accordance with §§ 97.606 and 97.624.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.630 through 97.635. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.606(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source during a control period in a given year that exceeds the TR SO_2 Group 1 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on ''average annual fuel consumption of fossil fuel'' in §§ 97.604(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the

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fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means ''natural gas'' as defined in § 72.2 of this chapter.

Newly affected TR SO_2 Group 1 unit means a unit that was not a TR SO_2 Group 1 unit when it began operating but that thereafter becomes a TR SO_2 Group 1 unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at a source respectively, any person who operates, controls, or supervises a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO_2 Group 1 unit; and

(3) Any purchaser of power from a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means ''permitting authority'' as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit, 33 percent of the unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to TR SO_2 Group 1 allowances, the moving of TR SO_2 Group 1 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 1 allowance, the unique identification number assigned to each TR SO_2 Group 1 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR SO_2 Group 1 Trading Program pursuant to § 52.39(a), (b), (d), (e), and (f) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

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Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

LHV = HHV ¥ 10.55(W + 9H)

Where:

LHV = lower heating value of the form of energy in Btu/lb,
HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.39(d), (e), or (f) of this chapter, to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR SO_2 Group 1 Trading Program.

TR SO_2 Group 1 allowance deduction or *deduct TR SO_2 Group 1 allowances* means the permanent withdrawal of TR SO_2 Group 1 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the TR SO_2 Group 1 emissions limitation) or from an assurance account (*e.g.,* in order to account for compliance with the assurance provisions under §§ 97.606 and 97.625).

TR SO_2 Group 1 allowances held or *hold TR SO_2 Group 1 allowances* means the TR SO_2 Group 1 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart.

TR SO_2 Group 1 emissions limitation means, for a TR SO_2 Group 1 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 1 allowances available for deduction for the source under § 97.624(a) for such control period.

TR SO_2 Group 1 source means a source that includes one or more TR SO_2 Group 1 units.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with this subpart and § 52.39(a), (b), (d) through (f), (j), and (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 1 unit means a unit that is subject to the TR SO_2 Group 1 Trading Program under § 97.604.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.603 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour lb—
pound mmBtu—million
Btu MWe—megawatt
electrical MWh—megawatt
hour NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million scfh—
standard cubic feet per hour SO_2—
sulfur dioxide
yr—year

§ 97.604 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR SO_2 Group 1 units, and any source that includes one or more such units shall be a TR SO_2 Group 1 source, subject to the requirements of this subpart: any stationary, fossil-fuel-fired boiler or

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stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 1 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 1 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR SO_2 Group 1 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR SO_2 Group 1 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR SO_2 Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a TR SO_2 Group 1 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR SO_2 Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR SO_2 Group 1 unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.39(e) or (f) of this chapter, of the TR SO_2 Group 1 Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: ''I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) Response. The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 1 Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.605 Retired unit exemption.

(a)(1) Any TR SO_2 Group 1 unit that is permanently retired shall be exempt from § 97.606(b) and (c)(1), § 97.624, and §§ 97.630 through 97.635.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 1 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

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§ 97.606 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.613 through 97.618.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.630 through 97.635.

(2) The emissions data determined in accordance with §§ 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under §§ 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements.* (1) TR SO_2 Group 1 emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under § 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii) If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under § 97.624(d); and

(B) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions. (i) If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under § 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR SO_2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total SO_2 emissions exceed the sum, for such control period, of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's variability limit under § 97.610(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods. A TR SO_2 Group 1 unit shall be subject to the requirements under paragraphs (c)(1) and (c)(2) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management

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System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.616 for the designated representative for the source and each TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR SO_2 Group 1 Trading Program, except as provided in § 97.618. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(2) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 1 Trading Program or exemption under § 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.607 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 1 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 1 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO_2 Group 1 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.608 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 1 Trading Program are set forth in part 78 of this chapter.

§ 97.609 [Reserved]

§ 97.610 State SO_2 Group 1 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State SO_2 Group 1 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR SO_2 Group 1 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 Group 1 trading budget (tons) * for 2012 and 2013	New unit set-aside (tons) for 2012 and 2013	Indian country new unit set-aside (tons) for 2012 and 2013
Illinois	234,889	11,744	
Indiana	285,424	8,563	
Iowa	107,085	2,035	107
Kentucky	232,662	13,960	
Maryland	30,120	602	
Michigan	229,303	4,357	229
Missouri	207,466	4,149	
New Jersey	5,574	111	

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State	SO_2 Group 1 trading budget (tons) * for 2012 and 2013	New unit set-aside (tons) for 2012 and 2013	Indian country new unit set-aside (tons) for 2012 and 2013
New York	27,325	520	27
North Carolina	136,881	10,813	137
Ohio	310,230	6,205	
Pennsylvania	278,651	5,573	
Tennessee	148,150	2,963	
Virginia	70,820	2,833	
West Virginia	146,174	10,232	
Wisconsin	79,480	3,894	80

State	SO_2 Group 1 trading budget (tons) * for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
Illinois	124,123	6,206	
Indiana	161,111	4,833	
Iowa	75,184	1,429	75
Kentucky	106,284	6,377	
Maryland	28,203	564	
Michigan	143,995	2,736	144
Missouri	165,941	3,319	
New Jersey	5,574	111	
New York	18,585	353	19
North Carolina	57,620	4,552	58
Ohio	137,077	2,742	
Pennsylvania	112,021	2,240	
Tennessee	58,833	1,177	
Virginia	35,057	1,402	
West Virginia	75,668	5,297	
Wisconsin	40,126	1,966	40

* Each trading budget includes the new unit set-aside and, where applicable, the Indian country new unit set-aside and does not include the variability limit.

(b) The States' variability limits for the State SO_2 Group 1 trading budgets for the control periods in 2012 and thereafter are as follows:

State	Variability limits for 2012 and 2013	Variability limits for 2014 and thereafter
Illinois	42,280	22,342
Indiana	51,376	29,000
Iowa	19,275	13,533
Kentucky	41,879	19,131
Maryland	5,422	5,077
Michigan	41,275	25,919
Missouri	37,344	29,869
New Jersey	1,003	1,003
New York	4,919	3,345
North Carolina	24,639	10,372
Ohio	55,841	24,674
Pennsylvania	50,157	20,164
Tennessee	26,667	10,590
Virginia	12,748	6,310
West Virginia	26,311	13,620
Wisconsin	14,306	7,223

§ 97.611 Timing requirements for TR SO_2 Group 1 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 1 allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR SO_2 Group 1 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR SO_2 Group 1 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR SO_2 Group 1 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR SO_2 Group 1 allowances that would otherwise have been allocated to such unit will be

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allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 1 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 1 allowance allocation to each TR SO_2 Group 1 unit in a State, in accordance with § 97.612(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO_2 Group 1 units) are in accordance with § 97.612(a)(2) through (7) and (12) and §§ 97.606(b)(2) and 97.630 through 97.635.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.612(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR SO_2 Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO_2 Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO_2 annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR SO_2 annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO_2 Group 1 units in each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR SO_2 Group 1 allowance allocation to each TR SO_2 Group 1 unit in accordance with § 97.612(a)(9), (10), and (12) and §§ 97.606(b)(2) and 97.630 through 97.635. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO_2 Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO_2 Group 1 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO_2 Group 1 allowances in accordance with § 97.612(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 1 allowance allocation to each TR SO_2 Group 1 unit in Indian country within the borders of a State, in accordance with § 97.612(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO_2 Group 1 units) are in accordance with § 97.612(b)(2) through (7) and (12) and §§ 97.606(b)(2) and 97.630 through 97.635.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.612(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR SO_2 Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO_2 Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO_2 annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR SO_2 annual units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO_2 Group 1 units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR SO_2 Group 1 allowance allocation to each TR SO_2 Group 1 unit in accordance with § 97.612(b)(9), (10),

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and (12) and §§ 97.606(b)(2) and 97.630 through 97.635. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO_2 Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO_2 Group 1 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO_X Annual allowances in accordance with § 97.612(b)(10).

(c) *Units incorrectly allocated TR SO_2* Group 1 allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 1 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.39(d), (e), or (f) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.612(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under § 52.39(e) or (f) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1, 2012 and is allocated TR SO_2 Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.39(d), (e), or (f) of this chapter, the recipient is not actually a TR SO_2 Group 1 unit as of January 1, 2012 and is allocated TR SO_2 Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO_2 Group 1 units as of January 1, 2012; or

(B) The recipient is not located as of January 1 of the control period in the State from whose SO_2 Group 1 trading budget the TR SO_2 Group 1 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.39(d), (e), or (f) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1 of such control period and is allocated TR SO_2 Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.39(d), (e), or (f) of this chapter, the recipient is not actually a TR SO_2 Group 1 unit as of January 1 of such control period and is allocated TR SO_2 Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO_2 Group 1 units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR SO_2 Group 1 allowances under § 97.621.

(3) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 1 allowances were recorded an amount of TR SO_2 Group 1 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 1 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 1 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 1 allowances.

(5)(i) With regard to the TR SO_2 Group 1 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR SO_2 Group 1 allowances to the new unit set-aside for such control period for the State from whose SO_2 Group 1 trading budget the TR SO_2 Group 1 allowances were allocated; or

(B) If the State has a SIP revision approved under § 52.39(e) or (f) covering such control period, include such TR SO_2 Group 1 allowances in the portion of the State SO_2 Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR SO_2 Group 1 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR SO_2 Group 1 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under § 52.39(e) or (f) covering such control period, include such TR SO_2 Group 1 allowances in the portion of the State SO_2 Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR SO_2 Group 1 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR SO_2 Group 1 allowances to the Indian country new unit set-aside for such control period.

§ 97.612 TR SO_2 Group 1 allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR SO_2 Group 1 units in each State, the Administrator will allocate TR SO_2 Group 1 allowances to the TR SO_2 Group 1 units as follows:

(1) The TR SO_2 Group 1 allowances will be allocated to the following TR SO_2 Group 1 units, except as provided in paragraph (a)(10) of this section:

(i) TR SO_2 Group 1 units that are not allocated an amount of TR SO_2 Group 1 allowances in the notice of data availability issued under § 97.611(a)(1);

(ii) TR SO_2 Group 1 units whose allocation of an amount of TR SO_2 Group 1 allowances for such control period in the notice of data availability issued under § 97.611(a)(1) is covered by § 97.611(c)(2) or (3);

(iii) TR SO_2 Group 1 units that are allocated an amount of TR SO_2 Group 1 allowances for such control period in

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the notice of data availability issued under § 97.611(a)(1), which allocation is terminated for such control period pursuant to § 97.611(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR SO_2 Group 1 units under § 97.611(c)(1)(ii) whose allocation of an amount of TR SO_2 Group 1 allowances for such control period in the notice of data availability issued under § 97.611(b)(1)(ii)(B) is covered by § 97.611(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR SO_2 Group 1 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.610(a) and will be allocated additional TR SO_2 Group 1 allowances (if any) in accordance with §§ 97.611(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR SO_2 Group 1 unit described in paragraph (a)(1) of this section, an allocation of TR SO_2 Group 1 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR SO_2 Group 1 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR SO_2 Group 1 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR SO_2 Group 1 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR SO_2 annual unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO_2 Group 1 allowances determined for all such TR SO_2 Group 1 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances determined for each such TR SO_2 Group 1 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR SO_2 Group 1 unit the amount of the TR SO_2 Group 1 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.611(b)(1)(i) and (ii), of the amount of TR SO_2 Group 1 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR SO_2 Group 1 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR SO_2 Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR SO_2 Group 1 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR SO_2 Group 1 allowances referenced in the notice of data availability required under § 97.611(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR SO_2 Group 1 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances determined for each such TR SO_2 Group 1 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO_2 Group 1 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR SO_2 Group 1 unit the amount of the TR SO_2 Group 1 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO_2 Group 1 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR SO_2 Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR SO_2 Group 1 unit that is in the State, is allocated an amount of TR SO_2 Group 1 allowances in the notice of data availability issued under § 97.611(a)(1), and continues to be allocated TR SO_2 Group 1 allowances for such control period in accordance with § 97.611(a)(2), an amount of TR SO_2 Group 1 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 1 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.611(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 1 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.611(b)(1)(iii), (iv), and (v), of the amount of TR SO_2 Group 1 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR SO_2 Group 1 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then

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the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR SO_2 Group 1 units in descending order based on the amount of such units' allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR SO_2 Group 1 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR SO_2 Group 1 units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (a)(10) of this section by one TR SO_2 Group 1 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR SO_2 Group 1 units located in Indian country within the borders of each State, the Administrator will allocate TR SO_2 Group 1 allowances to the TR SO_2 Group 1 units as follows:

(1) The TR SO_2 Group 1 allowances will be allocated to the following TR SO_2 Group 1 units, except as provided in paragraph (b)(10) of this section:

(i) TR SO_2 Group 1 units that are not allocated an amount of TR SO_2 Group 1 allowances in the notice of data availability issued under § 97.611(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR SO_2 Group 1 units under § 97.611(c)(1)(ii) whose allocation of an amount of TR SO_2 Group 1 allowances for such control period in the notice of data availability issued under § 97.611(b)(2)(ii)(B) is covered by § 97.611(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR SO_2 Group 1 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.610(a) and will be allocated additional TR SO_2 Group 1 allowances (if any) in accordance with § 97.611(c)(5).

(3) The Administrator will determine, for each TR SO_2 Group 1 unit described in paragraph (b)(1) of this section, an allocation of TR SO_2 Group 1 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR SO_2 Group 1 unit commences commercial operation.

(4)(i) The allocation to each TR SO_2 annual unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO_2 Group 1 allowances determined for all such TR SO_2 Group 1 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR SO_2 Group 1 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances determined for each such TR SO_2 Group 1 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR SO_2 Group 1 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR SO_2 Group 1 unit the amount of the TR SO_2 Group 1 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR SO_2 Group 1 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.611(b)(2)(i) and (ii), of the amount of TR SO_2 Group 1 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR SO_2 Group 1 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR SO_2 Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR SO_2 Group 1 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR SO_2 Group 1 allowances referenced in the notice of data availability required under § 97.611(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR SO_2 Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances determined for each such TR SO_2 Group 1 unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO_2 Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR SO_2 Group 1 unit the amount of the TR SO_2 Group 1 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO_2 Group 1 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum

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under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR SO_2 Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR SO_2 Group 1 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.39(d), (e), or (f) of this chapter covering such control period, include such unallocated TR SO_2 Group 1 allowances in the portion of the State SO_2 Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.611(b)(2)(iii), (iv), and (v), of the amount of TR SO_2 Group 1 allowances allocated under paragraphs (b)(9), (10), and (12) for such control period to each TR SO_2 Group 1 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (9)(iv) of this section, or paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR SO_2 Group 1 units in descending order based on the amount of such units' allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR SO_2 Group 1 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR SO_2 Group 1 units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one TR SO_2 Group 1 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.613 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.615, each TR SO_2 Group 1 source, including all TR SO_2 Group 1 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 1 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 1 unit at the source in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.615, each TR SO_2 Group 1 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.602, and §§ 97.614 through 97.618, whenever the term "designated representative" (as distinguished from the term "common designated representative") is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.614 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.618 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 1 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 1 source and TR SO_2 Group 1 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under

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penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.618.

§ 97.615 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.616, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.616 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR SO_2 Group 1 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.616 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.616 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 1 source, and each TR SO_2 Group 1 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 1 source and of each TR SO_2 Group 1 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 1 unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 1 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 1 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 1 unit at the source; and TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or distributed in proportion to each

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holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 1 allowances by contract, TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.617 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.616 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.616 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

§ 97.618 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d) shall be deemed to be an electronic submission by me.''

(ii) ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.618 is terminated.''.

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.619 [Reserved]

§ 97.620 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.616, the Administrator will establish a compliance account for the TR SO_2 Group 1 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.625(b)(3).

(c) *General accounts.* (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 1 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the

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following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.''

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 1 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 1 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate

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authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(c)(5)(iv) shall be deemed to be an electronic submission by me.''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.620(c)(5) is terminated.''.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 1 allowance transfer under § 97.622 for any TR SO_2 Group 1 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 1 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 1 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted TR SO_2 Group 1 allowance transfer under § 97.622 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 1 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.614(a) and 97.618 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 97.621 Recordation of TR SO_2 Group 1 allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with § 97.611(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with

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§ 97.611(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of § 52.39(d)(1) through (4) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with § 97.611(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with § 97.611(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 1 allowances auctioned to TR SO_2 Group 1 units, in accordance with § 97.611(a), or with a SIP revision approved under § 52.39(e) or (f) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 1 allowances auctioned to TR SO_2 Group 1 units, in accordance with § 97.611(a), or with a SIP revision approved under § 52.39(e) or (f) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 1 allowances auctioned to TR SO_2 Group 1 units, in accordance with § 97.611(a), or with a SIP revision approved under § 52.39(e) or (f) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 1 allowances auctioned to TR SO_2 Group 1 units, in accordance with § 97.611(a), or with a SIP revision approved under § 52.39(e) and (f) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 1 allowances auctioned to TR SO_2 Group 1 units, in accordance with § 97.612(a)(2) through (8) and (12), or with a SIP revision approved under § 52.39(e) and (f) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with § 97.612(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2013 and February 15 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 units at the source in accordance with § 97.612(a)(9) through (12), for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (i) of this section, of TR SO_2 Group 1 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.611 or § 97.612 or with a SIP revision approved under § 52.39(e) or (f) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR SO_2 Group 1 allowances to a TR SO_2 Group 1 unit or other entity in an Allowance Management System account, the Administrator will assign each TR SO_2 Group 1 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 1 allowance is allocated or auctioned.

§ 97.622 Submission of TR SO_2 Group 1 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 1 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 1 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 1 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 1 allowance identified by serial number in the transfer.

§ 97.623 Recordation of TR SO_2 Group 1 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 1 allowance transfer that is correctly submitted under § 97.622, the Administrator will record a TR SO_2 Group 1 allowance transfer by moving each TR SO_2 Group 1 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR SO_2 Group 1 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 1 allowances allocated for

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any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 97.624 for the control period immediately before such allowance transfer deadline.

(c) Where a TR SO_2 Group 1 allowance transfer is not correctly submitted under § 97.622, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 1 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 1 allowance transfer that is not correctly submitted under § 97.622, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.624 Compliance with TR SO_2 Group 1 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 1 allowances are available to be deducted for compliance with a source's TR SO_2 Group 1 emissions limitation for a control period in a given year only if the TR SO_2 Group 1 allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account TR SO_2 Group 1 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 1 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 1 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 1 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 1 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 1 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR SO_2 Group 1 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 1 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 1 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 1 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 1 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR SO_2 Group 1 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 1 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 1 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 1 allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.625 Compliance with TR SO_2 Group 1 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 1 allowances are available to be deducted for compliance with the TR SO_2 Group 1 assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR SO_2 Group 1 sources and units in a State (and Indian country within the borders of such State) only if the TR SO_2 Group 1 allowances:

(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR SO_2 Group 1 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 1 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 1 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2013 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total SO_2 emissions exceed the State assurance level as described in § 97.606(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions from each TR SO_2 Group 1 source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR SO_2 Group 1 units with total SO_2 emissions exceeding the State assurance level for a control period in a given year, as described in § 97.606(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 1 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR SO_2 Group 1 unit (if any) at the source that operates during, but is not allocated an amount of TR SO_2 Group 1 allowances for, such control period, the unit's allowable SO_2 emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more TR SO_2 Group 1 sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of TR SO_2 Group 1 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in § 97.606(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with § 97.606(c)(2)(iii), §§ 97.606(b) and 97.630 through 97.635, the definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share'' in § 97.602, and the calculation formula in § 97.606(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR SO_2 Group 1 units with total SO_2 emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR SO_2 Group 1 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR SO_2 Group 1 allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR SO_2 Group 1 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR SO_2 Group 1 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR SO_2 Group 1 allowances that the owners and operators are required to hold in accordance with § 97.606(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for such control period with regard to the TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR SO_2 Group 1 source and TR SO_2 Group 1 unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for such control period with regard to the TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR SO_2 Group 1 allowances that the owners and operators are required to hold for such control period with regard to the TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR SO_2 Group 1 allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR SO_2 Group 1 allowances in the assurance account established by the Administrator for the appropriate TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 1 allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR SO_2 Group 1 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR SO_2 Group 1 allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate TR SO_2 Group 1 sources, TR SO_2 Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR SO_2 Group 1 allowances held in such assurance account equal to the amount of the decrease. If TR SO_2 Group 1 allowances were transferred to such assurance account from more than one account, the amount of TR SO_2 Group 1 allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of TR SO_2 Group 1 allowances transferred to such assurance account for such control period from such transferor account.

(C) Each TR SO_2 Group 1 allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the TR SO_2 Group 1 assurance provisions for such control period must be a TR SO_2 Group 1 allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

§ 97.626 Banking.

(a) A TR SO_2 Group 1 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 1 allowance that is held in a compliance account or a general account will remain in such account unless and until the TR SO_2 Group 1 allowance is deducted or transferred under § 97.611(c), § 97.623, § 97.624, § 97.625, § 97.627, or § 97.628.

§ 97.627 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.628 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 1 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 1 allowances from or transfer TR SO_2 Group 1 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.629 [Reserved]

§ 97.630 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 1 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.602 and in § 72.2 of this chapter shall apply, the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''TR SO_2 Group 1 unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively as defined in § 97.602, and the term ''newly affected unit'' shall be deemed to mean ''newly affected TR SO_2 Group 1 unit''. The owner or operator of a unit that is not a TR SO_2 Group 1 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 1 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO_2 Group 1 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.631 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation before July 1, 2011, January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation on or after July 1, 2011, by the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation.

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(3) The owner or operator of a TR SO_2 Group 1 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §§ 75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under § 97.630 through § 97.635, rather than the monitoring systems required under part 75 of this chapter;

(ii) SO_2 concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.635, rather than § 75.66.

(c) *Reporting data.* The owner or operator of a TR SO_2 Group 1 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR SO_2 Group 1 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.635.

(2) No owner or operator of a TR SO_2 Group 1 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 to the atmosphere without accounting for all such SO_2 in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO_2 Group 1 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO_2 Group 1 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.605 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.631(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR SO_2 Group 1 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.631 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 1 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.630(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.630(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 1 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.630(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.630(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.630(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.630(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.630(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under § 97.630(a)(1), paragraphs (d)(3)(i) through (v) of this

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section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words ''certification'' and ''initial certification'' are replaced by the word ''recertification'' and the word ''certified'' is replaced by the word ''recertified''.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.633.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 1 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR SO_2 Group 1 Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.632(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.632 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system

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and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.631 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.631 for each disapproved monitoring system.

§ 97.633 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 1 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.634 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.614(a).

(b) *Monitoring plans.* The owner or operator of a TR SO_2 Group 1 unit shall comply with requirements of § 75.62 of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.631, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.630(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 1 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.635 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 1 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.630 through 97.634.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with

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the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

77. Part 97 is amended by adding subpart DDDDD to read as follows:

Subpart DDDDD—TR SO_2 Group 2 Trading Program

Sec.

Subpart DDDDD—TR SO_2 Group 2 Trading Program

§ 97.701 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 2 Trading Program, under section 110 of the Clean Air Act and § 52.39 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

§ 97.702 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to TR SO_2 Group 2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.39(g), (h), or (i) of this chapter, of the amount of such TR SO_2 Group 2 allowances to be initially credited, at no cost to the recipient, to:

(1) A TR SO_2 Group 2 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a TR SO_2 Group 2 unit qualifying for an initial credit, a credit in the amount of zero TR SO_2 Group 2 allowances, the TR SO_2 Group 2 unit will be treated as being allocated an amount (*i.e.*, zero) of TR SO_2 Group 2 allowances.

Allowable SO_2 emission rate means, for a unit, the most stringent State or federal SO_2 emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit's heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 2 allowances under the TR SO_2 Group 2 Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 2 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 2 allowance transfer must be submitted for recordation in a TR SO_2 Group 2 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 2 emissions limitation for such control period in accordance with §§ 97.706 and 97.724.

Alternate designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.725(b)(3) for certain owners and operators of a group of one or more TR SO_2 Group 2 sources and units in a given State (and Indian country within the borders of such State), in which are held TR SO_2 Group 2 allowances available for use for a control period in a given year in

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complying with the TR SO_2 Group 2 assurance provisions in accordance with §§ 97.706 and 97.725.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 2 allowances held in the general account and, for a TR SO_2 Group 2 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means ''coal'' as defined in § 72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.705.

(i) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.705, for a unit that is not a TR SO_2 Group 2 unit under § 97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 2 unit under § 97.704.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition

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and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§ 97.713(a) and 97.715(a) as the designated representative for a group of one or more TR SO_2 Group 2 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.706(c)(2)(iii), the common designated representative's share of the State SO_2 Group 2 trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of SO_2 emissions during such control period from a group of one or more TR SO_2 Group 2 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State SO_2 Group 2 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR SO_2 Group 2 allowances allocated for such control period to a group of one or more TR SO_2 Group 2 units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR SO_2 Group 2 allowances purchased by an owner or operator of such TR SO_2 Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR SO_2 Group 2 units in accordance with the TR SO_2 Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.39(h) or (i) of this chapter, multiplied by the sum of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's variability limit under § 97.710(b) for such control period and divided by such State SO_2 Group 2 trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR SO_2 Group 2 allowances allocated under §§ 97.711 and 97.712 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 2 allowances for such control period equal to the unit's allowable SO_2 emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 2 source under this subpart, in which any TR SO_2 Group 2 allowance allocations to the TR SO_2 Group 2 units at the source are recorded and in which are held any TR SO_2 Group 2 allowances available for use for a control period in a given year in complying with the source's TR SO_2 Group 2 emissions limitation in accordance with §§ 97.706 and 97.724.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.730 through 97.735. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.706(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same

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natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR SO_2 Group 2 units at a TR SO_2 Group 2 source during a control period in a given year that exceeds the TR SO_2 Group 2 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on ''average annual fuel consumption of fossil fuel'' in §§ 97.704(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means ''natural gas'' as defined in § 72.2 of this chapter.

Newly affected TR SO_2 Group 2 unit means a unit that was not a TR SO_2 Group 2 unit when it began operating but that thereafter becomes a TR SO_2 Group 2 unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at a source respectively, any person who operates, controls, or supervises a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO_2 Group 2 unit; and

(3) Any purchaser of power from a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means ''permitting authority'' as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit, 33 percent of the unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document,

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information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to TR SO_2 Group 2 allowances, the moving of TR SO_2 Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 2 allowance, the unique identification number assigned to each TR SO_2 Group 2 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR SO_2 Group 2 Trading Program pursuant to § 52.39(a), (c), (g), (h), and (i) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV ¥ 10.55(W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.39(g), (h), or (i) of this chapter, to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR SO_2 Group 2 Trading Program.

TR SO_2 Group 2 allowance deduction or *deduct TR SO_2* Group 2 allowances means the permanent withdrawal of TR SO_2 Group 2 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the TR SO_2 Group 2 emissions limitation) or from an assurance account (*e.g.,* in order to account for compliance with the assurance provisions under §§ 97.706 and 97.725).

TR SO_2 Group 2 allowances held or *hold TR SO_2* Group 2 allowances means the TR SO_2 Group 2 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart.

TR SO_2 Group 2 emissions limitation means, for a TR SO_2 Group 2 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 2 allowances available for deduction for the source under § 97.724(a) for such control period.

TR SO_2 Group 2 source means a source that includes one or more TR SO_2 Group 2 units.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with this subpart and § 52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 unit means a unit that is subject to the TR SO_2 Group 2 Trading Program under § 97.704.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.703 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour lb—
pound mmBtu—million
Btu MWe—megawatt
electrical MWh—megawatt
hour NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million scfh—
standard cubic feet per hour SO_2—
sulfur dioxide
yr—year

§ 97.704 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR SO_2 Group 2 units, and any source that includes one or more such units shall be a TR SO_2 Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR SO_2 Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR SO_2 Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR SO_2 Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a TR SO_2 Group 2 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR SO_2 Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR SO_2 Group 2 unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.39(h) or (i) of this chapter, of the TR SO_2 Group 2 Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) Response. The Administrator will issue a written response to the petition

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and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 2 Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.705 Retired unit exemption.

(a)(1) Any TR SO_2 Group 2 unit that is permanently retired shall be exempt from § 97.706(b) and (c)(1), § 97.724, and §§ 97.730 through 97.735.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.706 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.713 through 97.718.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.730 through 97.735.

(2) The emissions data determined in accordance with §§ 97.730 through 97.735 shall be used to calculate allocations of TR SO_2 Group 2 allowances under §§ 97.711(a)(2) and (b) and 97.712 and to determine compliance with the TR SO_2 Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements.* (1) TR SO_2 Group 2 emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 2 allowances available for deduction for such control period under § 97.724(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 2 units at the source.

(ii) If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 2 units at a TR SO_2 Group 2 source are in excess of the TR SO_2 Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall hold the TR SO_2 Group 2 allowances required for deduction under § 97.724(d); and

(B) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR SO_2 Group 2 assurance provisions. (i) If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 2 units at TR SO_2 Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 2 allowances available for deduction for such control period under § 97.725(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.725(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO_2 emissions from all TR SO_2 Group 2 units at TR SO_2 Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR SO_2 Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO_2 emissions from all TR SO_2 Group 2 units at TR SO_2 Group 2

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sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total SO_2 emissions exceed the sum, for such control period, of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's variability limit under § 97.710(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 2 units at TR SO_2 Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 2 units at TR SO_2 Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR SO_2 Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods. A TR SO_2 Group 2 unit shall be subject to the requirements under paragraphs (c)(1) and (c)(2) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.730(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR SO_2 Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR SO_2 Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO_2 Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR SO_2 Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO_2 Group 2 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO_2 Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 2 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.730 through 97.735 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.716 for the designated representative for the source and each TR SO_2 Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.716 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 2 Trading Program.

(2) The designated representative of a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall make all submissions required under the TR SO_2 Group 2 Trading Program, except as provided in § 97.718. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 source or the designated representative of a TR SO_2 Group 2 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 2 units at the source.

(2) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 unit or the designated representative of a TR SO_2 Group 2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 2 Trading Program or exemption under § 97.705 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 2 source or TR SO_2 Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

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§ 97.707 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO_2 Group 2 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.708 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 2 Trading Program are set forth in part 78 of this chapter.

§ 97.709 [Reserved]

§ 97.710 State SO_2 Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State SO_2 Group 2 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR SO_2 Group 2 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 Group 2 trading budget (tons) * for 2012 and 2013	New unit set-aside (tons) for 2012 and 2013	Indian country new unit set-aside (tons) for 2012 and 2013
Alabama	216,033	4,321	
Georgia	158,527	3,171	
Kansas	41,528	789	42
Minnesota	41,981	798	42
Nebraska	65,052	2,537	65
South Carolina	88,620	1,683	89
Texas	243,954	11,954	244

State	SO_2 Group 2 trading budget (tons) * for 2014 and thereafter	New unit set-aside (tons) for 2014 and thereafter	Indian country new unit set-aside (tons) for 2014 and thereafter
Alabama	213,258	4,265	
Georgia	95,231	1,905	
Kansas	41,528	789	42
Minnesota	41,981	798	42
Nebraska	65,052	2,537	65
South Carolina	88,620	1,683	89
Texas	243,954	11,954	244

* Each trading budget includes the new unit set-aside and, where applicable, the Indian country new unit set-aside and does not include the variability limit.

(b) The States' variability limits for the State SO_2 Group 2 trading budgets for the control periods in 2012 and thereafter are as follows:

State	Variability limits for 2012 and 2013	Variability limits for 2014 and thereafter
Alabama	38,886	38,386
Georgia	28,535	17,142
Kansas	7,475	7,475
Minnesota	7,557	7,557
Nebraska	11,709	11,709
South Carolina	15,952	15,952
Texas	43,912	43,912

§ 97.711 Timing requirements for TR SO_2 Group 2 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 2 allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR SO_2 Group 2 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR SO_2 Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR SO_2 Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR SO_2 Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 2 allowances to the unit in accordance with paragraph (b) of this section.

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(b) *New units.* (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 2 allowance allocation to each TR SO_2 Group 2 unit in a State, in accordance with § 97.712(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO_2 Group 2 units) are in accordance with § 97.712(a)(2) through (7) and (12) and §§ 97.706(b)(2) and 97.730 through 97.735.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.712(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR SO_2 Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO_2 Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO_2 annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR SO_2 annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO_2 Group 2 units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR SO_2 Group 2 allowance allocation to each TR SO_2 Group 2 unit in accordance with § 97.712(a)(9), (10), and (12) and §§ 97.706(b)(2) and 97.730 through 97.735. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO_2 Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO_2 Group 2 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO_2 Group 2 allowances in accordance with § 97.712(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 2 allowance allocation to each TR SO_2 Group 2 unit in Indian country within the borders of a State, in accordance with § 97.712(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO_2 Group 2 units) are in accordance with § 97.712(b)(2) through (7) and (12) and §§ 97.706(b)(2) and 97.730 through 97.735.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.712(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR SO_2 Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO_2 Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO_2 annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR SO_2 annual units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO_2 Group 2 units in the each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR SO_2 Group 2 allowance allocation to each TR SO_2 Group 2 unit in accordance with § 97.712(b)(9), (10), and (12) and §§ 97.706(b)(2) and 97.730 through 97.735. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO_2 Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO_2 Group 2 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO_2 Group 2 allowances in accordance with § 97.712(b)(10).

(c) *Units incorrectly allocated TR SO_2* Group 2 allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 2 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved § 52.39(g), (h), or (i) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.712(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved § 52.39(h) or (i) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1, 2012 and is allocated TR SO_2 Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.39(g), (h), or (i) of this chapter, the recipient is not actually a TR SO_2 Group 2 unit as of January 1, 2012 and is allocated TR SO_2 Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO_2 Group 2 units as of January 1, 2012; or

(B) The recipient is not located as of January 1 of the control period in the State from whose SO_2 Group 2 trading budget the TR SO_2 Group 2 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.39(g), (h), or (i) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1 of such control period and is allocated TR SO_2 Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.39(g), (h), or (i) of this chapter, the recipient is not actually a TR SO_2 Group 2 unit as of January 1 of such control period and is allocated TR SO_2 Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO_2 Group 2 units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR SO_2 Group 2 allowances under § 97.721.

(3) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 2 allowances were recorded an amount of TR SO_2 Group 2 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 2 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 2 allowances.

(5)(i) With regard to the TR SO_2 Group 2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR SO_2 Group 2 allowances to the new unit set-aside for such control period for the State from whose SO_2 Group 2 trading budget the TR SO_2 Group 2 allowances were allocated; or

(B) If the State has a SIP revision approved under § 52.39(h) or (i) covering such control period, include such TR SO_2 Group 2 allowances in the portion of the State SO_2 Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR SO_2 Group 2 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR SO_2 Group 2 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under § 52.39(h) or (i) covering such control period, include such TR SO_2 Group 2 allowances in the portion of the State SO_2 Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR SO_2 Group 2 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR SO_2 Group 2 allowances to the Indian country new unit set-aside for such control period.

§ 97.712 TR SO_2 Group 2 allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR SO_2 Group 2 units in each State, the Administrator will allocate TR SO_2 Group 2 allowances to the TR SO_2 Group 2 units as follows:

(1) The TR SO_2 Group 2 allowances will be allocated to the following TR SO_2 Group 2 units, except as provided in paragraph (a)(10) of this section:

(i) TR SO_2 Group 2 units that are not allocated an amount of TR SO_2 Group 2 allowances in the notice of data availability issued under § 97.711(a)(1);

(ii) TR SO_2 Group 2 units whose allocation of an amount of TR SO_2 Group 2 allowances for such control period in the notice of data availability issued under § 97.711(a)(1) is covered by § 97.711(c)(2) or (3);

(iii) TR SO_2 Group 2 units that are allocated an amount of TR SO_2 Group 2 allowances for such control period in the notice of data availability issued under § 97.711(a)(1), which allocation is terminated for such control period pursuant to § 97.711(a)(2), and that operate during the control period

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immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR SO_2 Group 2 units under § 97.711(c)(1)(ii) whose allocation of an amount of TR SO_2 Group 2 allowances for such control period in the notice of data availability issued under § 97.711(b)(1)(ii)(B) is covered by § 97.711(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR SO_2 Group 2 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.710(a) and will be allocated additional TR SO_2 Group 2 allowances (if any) in accordance with §§ 97.711(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR SO_2 Group 2 unit described in paragraph (a)(1) of this section, an allocation of TR SO_2 Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR SO_2 Group 2 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR SO_2 Group 2 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR SO_2 Group 2 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR SO_2 annual unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO_2 Group 2 allowances determined for all such TR SO_2 Group 2 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances determined for each such TR SO_2 Group 2 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR SO_2 Group 2 unit the amount of the TR SO_2 Group 2 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.711(b)(1)(i) and (ii), of the amount of TR SO_2 Group 2 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR SO_2 Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR SO_2 Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR SO_2 Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR SO_2 Group 2 allowances referenced in the notice of data availability required under § 97.711(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR SO_2 Group 2 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances determined for each such TR SO_2 Group 2 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO_2 Group 2 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR SO_2 Group 2 unit the amount of the TR SO_2 Group 2 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO_2 Group 2 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR SO_2 Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR SO_2 Group 2 unit that is in the State, is allocated an amount of TR SO_2 Group 2 allowances in the notice of data availability issued under § 97.711(a)(1), and continues to be allocated TR SO_2 Group 2 allowances for such control period in accordance with § 97.711(a)(2), an amount of TR SO_2 Group 2 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 2 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.711(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 2 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.711(b)(1)(iii), (iv), and (v), of the amount of TR SO_2 Group 2 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR SO_2 Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR SO_2 Group 2 units in descending order based

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on the amount of such units' allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR SO_2 Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR SO_2 Group 2 units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (a)(10) of this section by one TR SO_2 Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR SO_2 Group 2 units located in Indian country within the borders of each State, the Administrator will allocate TR SO_2 Group 2 allowances to the TR SO_2 Group 2 units as follows:

(1) The TR SO_2 Group 2 allowances will be allocated to the following TR SO_2 Group 2 units, except as provided in paragraph (b)(10) of this section:

(i) TR SO_2 Group 2 units that are not allocated an amount of TR SO_2 Group 2 allowances in the notice of data availability issued under § 97.711(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR SO_2 Group 2 units under § 97.711(c)(1)(ii) whose allocation of an amount of TR SO_2 Group 2 allowances for such control period in the notice of data availability issued under § 97.711(b)(2)(ii)(B) is covered by § 97.711(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR SO_2 Group 2 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.710(a) and will be allocated additional TR SO_2 Group 2 allowances (if any) in accordance with § 97.711(c)(5).

(3) The Administrator will determine, for each TR SO_2 Group 2 unit described in paragraph (b)(1) of this section, an allocation of TR SO_2 Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR SO_2 Group 2 unit commences commercial operation.

(4)(i) The allocation to each TR SO_2 annual unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO_2 Group 2 allowances determined for all such TR SO_2 Group 2 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR SO_2 Group 2 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances determined for each such TR SO_2 Group 2 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR SO_2 Group 2 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR SO_2 Group 2 unit the amount of the TR SO_2 Group 2 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR SO_2 Group 2 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.711(b)(2)(i) and (ii), of the amount of TR SO_2 Group 2 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR SO_2 Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR SO_2 Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR SO_2 Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of TR SO_2 Group 2 allowances referenced in the notice of data availability required under § 97.711(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR SO_2 Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances determined for each such TR SO_2 Group 2 unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO_2 Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR SO_2 Group 2 unit the amount of the TR SO_2 Group 2 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO_2 Group 2 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control

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period, any unallocated TR SO_2 Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR SO_2 Group 2 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.39(g), (h), or (i) of this chapter covering such control period, include such unallocated TR SO_2 Group 2 allowances in the portion of the State SO_2 Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.711(b)(2)(iii), (iv), and (v), of the amount of TR SO_2 Group 2 allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each TR SO_2 Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (9)(iv) of this section, or paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR SO_2 Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR SO_2 Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR SO_2 Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one TR SO_2 Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.713 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.715, each TR SO_2 Group 2 source, including all TR SO_2 Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 2 unit at the source in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.715, each TR SO_2 Group 2 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.702, and §§ 97.714 through 97.718, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.714 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.718 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 2 source and TR SO_2 Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of

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those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.718.

§ 97.715 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.716, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.716 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR SO_2 Group 2 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.716 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.716 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 2 source, and each TR SO_2 Group 2 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 2 source and of each TR SO_2 Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 2 unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 2 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 2 unit at the source; and TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 2

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allowances by contract, TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2 allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.717 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.716 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.716 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

§ 97.718 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d) shall be deemed to be an electronic submission by me.''

(ii) ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.718 is terminated.''.

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.719 [Reserved]

§ 97.720 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.716, the Administrator will establish a compliance account for the TR SO_2 Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.725(b)(3).

(c) *General accounts.* (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 2 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and

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facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO_2 Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.''

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and

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received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(c)(5)(iv) shall be deemed to be an electronic submission by me.''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.720(c)(5) is terminated.''.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 2 allowance transfer under § 97.722 for any TR SO_2 Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted TR SO_2 Group 2 allowance transfer under § 97.722 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.714(a) and 97.718 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 97.721 Recordation of TR SO_2 Group 2 allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in 2013, unless the State in which the source is located notifies the

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Administrator in writing by October 17, 2011 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of § 52.39(g)(1) through (4) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 2 allowances auctioned to TR SO_2 Group 2 units, in accordance with § 97.711(a), or with a SIP revision approved under § 52.39(h) or (i) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 2 allowances auctioned to TR SO_2 Group 2 units, in accordance with § 97.711(a), or with a SIP revision approved under § 52.39(h) or (i) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 2 allowances auctioned to TR SO_2 Group 2 units, in accordance with § 97.711(a), or with a SIP revision approved under § 52.39(h) or (i) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 2 allowances auctioned to TR SO_2 Group 2 units, in accordance with § 97.711(a), or with a SIP revision approved under § 52.39(h) and (i) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO_2 Group 2 allowances auctioned to TR SO_2 Group 2 units, in accordance with § 97.712(a)(2) through (8) and (12), or with a SIP revision approved under § 52.39(h) and (i) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.712(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2013 and February 15 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 units at the source in accordance with § 97.712(a)(9) through (12), for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results, described in paragraphs (a) through (i) of this section, of TR SO_2 Group 2 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.711 or § 97.712 or with a SIP revision approved under § 52.39(h) or (i) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR SO_2 Group 2 allowances to a TR SO_2 Group 2 unit or other entity in an Allowance Management System account, the Administrator will assign each TR SO_2 Group 2 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 2 allowance is allocated or auctioned.

§ 97.722 Submission of TR SO_2 Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 2 allowance identified by serial number in the transfer.

§ 97.723 Recordation of TR SO_2 Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 2 allowance transfer that is correctly submitted under § 97.722, the Administrator will record a TR SO_2 Group 2 allowance transfer by moving each TR SO_2 Group 2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR SO_2 Group 2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such

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compliance account under § 97.724 for the control period immediately before such allowance transfer deadline.

(c) Where a TR SO_2 Group 2 allowance transfer is not correctly submitted under § 97.722, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 2 allowance transfer that is not correctly submitted under § 97.722, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.724 Compliance with TR SO_2 Group 2 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 2 allowances are available to be deducted for compliance with a source's TR SO_2 Group 2 emissions limitation for a control period in a given year only if the TR SO_2 Group 2 allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account TR SO_2 Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 2 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 2 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR SO_2 Group 2 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 2 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR SO_2 Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 2 allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.725 Compliance with TR SO_2 Group 2 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 2 allowances are available to be deducted for compliance with the TR SO_2 Group 2 assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR SO_2 Group 2 sources and units in a State (and Indian country within the borders of such State) only if the TR SO_2 Group 2 allowances:

(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR SO_2 Group 2 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 2 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2013 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total SO_2 emissions from all TR SO_2 Group 2 units at TR SO_2 Group 2 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total SO_2 emissions exceed the State assurance level as described in § 97.706(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions from each TR SO_2 Group 2 source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR SO_2 Group 2 units with total SO_2 emissions exceeding the State assurance level for a control period in a given year, as described in § 97.706(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 2 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR SO_2 Group 2 unit (if any) at the source that operates during, but is not allocated an amount of TR SO_2 Group 2 allowances for, such control period, the unit's allowable SO_2 emission rate for such control period and, if such rate is

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expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more TR SO_2 Group 2 sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total SO_2 emissions from all TR SO_2 Group 2 units at TR SO_2 Group 2 sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of TR SO_2 Group 2 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in § 97.706(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with § 97.706(c)(2)(iii), §§ 97.706(b) and 97.730 through 97.735, the definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share'' in § 97.702, and the calculation formula in § 97.706(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR SO_2 Group 2 units with total SO_2 emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR SO_2 Group 2 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR SO_2 Group 2 allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR SO_2 Group 2 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR SO_2 Group 2 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR SO_2 Group 2 allowances that the owners and operators are required to hold in accordance with § 97.706(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for such control period with regard to the TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR SO_2 Group 2 source and TR SO_2 Group 2 unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for such control period with regard to the TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR SO_2 Group 2 allowances that the owners and operators are required to hold for such control period with regard to the TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR SO_2 Group 2 allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR SO_2 Group 2 allowances in the assurance account established by the Administrator for the appropriate TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 2 allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR SO_2 Group 2 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR SO_2 Group 2 allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate at TR SO_2 Group 2 sources, TR SO_2 Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR SO_2 Group 2 allowances held in such assurance account equal to the amount of the decrease. If TR SO_2 Group 2 allowances were transferred to such assurance account from more than one account, the amount of TR SO_2 Group 2 allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of TR SO_2 Group 2 allowances transferred to such assurance account for such control period from such transferor account.

(C) Each TR SO_2 Group 2 allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the TR SO_2 Group 2 assurance provisions for such control period must be a TR SO_2 Group 2 allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

§ 97.726 Banking.

(a) A TR SO_2 Group 2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 2 allowance that is held in a compliance account or a general account will remain in such account unless and until the TR SO_2 Group 2 allowance is deducted or transferred under § 97.711(c), § 97.723, § 97.724, § 97.725, § 97.727, or § 97.728.

§ 97.727 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.728 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 2 allowances from or transfer TR SO_2 Group 2 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.729 [Reserved]

§ 97.730 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.702 and in § 72.2 of this chapter shall apply, the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''TR SO_2 Group 2 unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively as defined in § 97.702, and the term ''newly affected unit'' shall be deemed to mean ''newly affected TR SO_2 Group 2 unit''. The owner or operator of a unit that is not a TR SO_2 Group 2 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 2 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO_2 Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.731 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation before July 1, 2011, January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation on or after July 1, 2011, by the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation.

(3) The owner or operator of a TR SO_2 Group 2 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline

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under paragraph (b)(1) or (2) of this section shall meet the requirements of §§ 75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under § 97.730 through § 97.735, rather than the monitoring systems required under part 75 of this chapter;

(ii) SO_2 concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.735, rather than § 75.66.

(c) *Reporting data*. The owner or operator of a TR SO_2 Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) *Prohibitions*. (1) No owner or operator of a TR SO_2 Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.735.

(2) No owner or operator of a TR SO_2 Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 to the atmosphere without accounting for all such SO_2 in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO_2 Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO_2 Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.705 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.731(d)(3)(i).

(e) *Long-term cold storage*. The owner or operator of a TR SO_2 Group 2 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.731 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.730(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.730(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.730(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.730(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.730(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.730(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.730(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under § 97.730(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the

procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words ''certification'' and ''initial certification'' are replaced by the word ''recertification'' and the word ''certified'' is replaced by with the word ''recertified''.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.733.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR SO_2 Group 2 Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.732(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.732 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.731 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.731 for each disapproved monitoring system.

§ 97.733 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 2 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.734 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.714(a).

(b) *Monitoring plans.* The owner or operator of a TR SO_2 Group 2 unit shall comply with requirements of § 75.62 of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.731, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.730(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 2 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.735 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 2 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.730 through 97.734.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any

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adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 78, and 97

[EPA–HQ–OAR–2015–0500; FRL–9950–30–OAR]

RIN 2060–AS05

Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) published the original Cross-State Air Pollution Rule (original CSAPR) on August 8, 2011, to address interstate transport of ozone pollution under the 1997 ozone National Ambient Air Quality Standards (NAAQS) and interstate transport of fine particulate matter ($PM_{2.5}$) pollution under the 1997 and 2006 $PM_{2.5}$ NAAQS. The EPA is finalizing this Cross-State Air Pollution Rule Update (CSAPR Update) to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS. This final rule will benefit human health and welfare by reducing ground-level ozone pollution. In particular, it will reduce ozone season emissions of oxides of nitrogen (NO_X) in 22 eastern states that can be transported downwind as NO_X or, after transformation in the atmosphere, as ozone, and can negatively affect air quality and public health in downwind areas.

For these 22 eastern states, the EPA is issuing Federal Implementation Plans (FIPs) that generally provide updated CSAPR NO_X ozone season emission budgets for the electric generating units (EGUs) within these states, and that implement these budgets via modifications to the CSAPR NO_X ozone season allowance trading program that was established under the original CSAPR. The EPA is finalizing these new or revised FIP requirements only for certain states that have failed to submit an approvable State Implementation Plan (SIP) addressing interstate emission transport for the 2008 ozone NAAQS. The FIPs require affected EGUs in each covered state to reduce emissions to comply with program requirements beginning with the 2017 ozone season (May 1 through September 30). This final rule partially addresses the EPA's obligation under the Clean Air Act to promulgate FIPs to address interstate emission transport for the 2008 ozone NAAQS. In conjunction with other federal and state actions to reduce ozone pollution, these requirements will assist downwind states in the eastern United States with attaining and maintaining the 2008 ozone NAAQS.

This CSAPR Update also is intended to address the July 28, 2015 remand by the United States Court of Appeals for the District of Columbia Circuit of certain states' original CSAPR phase 2 ozone season NO_X emission budgets. In addition, this rule updates the status of certain states' outstanding interstate ozone transport obligations with respect to the 1997 ozone NAAQS, for which the original CSAPR provided a partial remedy.

DATES: This final rule is effective on December 27, 2016.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2015–0500. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov*.

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SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CAMx Comprehensive Air Quality Model With Extensions
CBI Confidential Business Information
CEMS Continuous Emission Monitoring Systems
CFR Code of Federal Regulations
CSAPR Cross-State Air Pollution Rule
EGU Electric Generating Unit
EPA U.S. Environmental Protection Agency
FIP Federal Implementation Plan
FR Federal Register
GWh Gigawatt Hours
ICR Information Collection Request
IPM Integrated Planning Model
Km Kilometer
lb/mmBtu Pounds per Million British Thermal Unit
LNB Low-NO_X Burners
mmBtu Million British Thermal Unit
MOVES Motor Vehicle Emission Simulator
NAAQS National Ambient Air Quality Standard
NBP NO_X Budget Trading Program
NEI National Emission Inventory
NO_X Nitrogen Oxides
NODA Notice of Data Availability
NSPS New Source Performance Standard
OFA Overfire Air
$PM_{2.5}$ Fine Particulate Matter
PPB Parts Per Billion
RIA Regulatory Impact Analysis
SC–CO_2 Social Cost of Carbon
SCR Selective Catalytic Reduction
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
TSD Technical Support Document

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I. Executive Summary

The EPA published the original Cross-State Air Pollution Rule (original CSAPR) [1] on August 8, 2011 to address the interstate transport of emissions with respect to the 1997 ozone National Ambient Air Quality Standards (NAAQS) and the 1997 and 2006 fine particulate matter ($PM_{2.5}$) NAAQS.[2] The EPA is finalizing this Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS (CSAPR Update) to address the interstate transport of emissions with respect to the 2008 ozone NAAQS. The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb).[3] The EPA proposed the CSAPR Update with respect to the 2008 ozone NAAQS on December 3, 2015 (80 FR 75706), and solicited comment on that action. The EPA provided an additional opportunity to comment on the air quality modeling platform and air quality modeling results that were used for the proposed CSAPR Update, through an August 4, 2015 Notice of Data Availability (NODA) (80 FR 46271) requesting comment on these data. This final rule is informed by comments received on the NODA and proposed CSAPR Update. This CSAPR Update also is intended to address the remand by the United States Court of Appeals for the District of Columbia Circuit of certain states' original CSAPR NO_X ozone season phase 2 emission budgets. Additionally, this rule updates the status of outstanding interstate ozone transport obligations for states that the original CSAPR provided a partial remedy with respect to the 1997 ozone NAAQS.

A. Purpose of Regulatory Action

The purpose of this rulemaking is to protect public health and welfare by reducing interstate emission transport that significantly contributes to nonattainment, or interferes with maintenance, of the 2008 ozone NAAQS in the eastern U.S. Ground-level ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems, for example, by limiting tree growth.

Studies have established that ozone occurs on a regional scale (*i.e.,* hundreds of miles) over much of the eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas.[4] [5] To reduce this regional-scale ozone transport, assessments of ozone control approaches have concluded that NO_X control strategies are effective. Further, studies have found that EGU NO_X emission reductions can be effective in reducing ozone pollution—specifically 8-hour peak concentrations, which is the form of the 2008 ozone standard. For example, studies have shown EGU NO_X reductions achieved under one of the EPA's prior interstate transport rulemakings known as the NO_X SIP Call [6] were effective in reducing 8-hour peak ozone concentrations during the ozone season.[7]

Clean Air Act (CAA or the Act) section 110(a)(2)(D)(i)(I), sometimes called the ''good neighbor provision,''

[1] *See* 76 FR 48208 (August 8, 2011).

[2] The original CSAPR did not evaluate the 2008 ozone standard because the 2008 ozone NAAQS was under reconsideration during the analytic work for the rule.

[3] *See* 73 FR 16436 (March 27, 2008).

[4] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[5] Liao, K. et al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[6] 63 FR 57356 (October 27, 1998).

[7] Gégo et al. (2007) Observation-based assessment of the impact of nitrogen oxides emissions reductions on O_3 air quality over the eastern United States. J. of Applied Meteorology and Climatology 46: 994–1008.

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requires states [8] to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS. The statute vests states with the primary responsibility to address interstate emission transport through the development of good neighbor State Implementation Plans (SIPs). The EPA supports state efforts to submit good neighbor SIPs for the 2008 ozone NAAQS and has shared information with states to facilitate such SIP submittals. However, the CAA also requires the EPA to fill a backstop role by issuing Federal Implementation Plans (FIPs) where states fail to submit good neighbor SIPs or the EPA disapproves a submitted good neighbor SIP.

On July 13, 2015, the EPA published a rule finding that 24 states [9] failed to make complete submissions that address the requirements of section 110(a)(2)(D)(i)(I) related to the interstate transport of pollution as to the 2008 ozone NAAQS. *See* 80 FR 39961 (July 13, 2015) (effective August 12, 2015). This CSAPR Update finalizes FIPs for 13 of these states (Alabama, Arkansas, Illinois, Iowa, Kansas, Michigan, Mississippi, Missouri, Oklahoma, Pennsylvania, Tennessee, Virginia, and West Virginia). On June 15, 2016 and July 20, 2016, the EPA published additional rules finding that New Jersey and Maryland, respectively, also failed to submit transport SIPs for the 2008 ozone NAAQS. *See* 81 FR 38963 (June 15, 2016) (effective July 15, 2016); 81 FR 47040 (July 20, 2016) (Maryland, effective August 19, 2016). This final CSAPR Update also finalizes FIPs addressing the good neighbor provision for these two states. Additionally, the EPA is finalizing FIPs for seven states for which it finalized disapproval of the states' good neighbor SIPs for the 2008 ozone NAAQS: Indiana, Kentucky, Louisiana, New York, Ohio, Texas, and Wisconsin. The FIPs being promulgated partially address the EPA's outstanding CAA obligations to prohibit interstate transport of air pollution which will contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the 2008 ozone NAAQS. The EPA also determines that it has fully satisfied its FIP obligation as to 9 states (Florida, Georgia, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, South Carolina, and Vermont), which the EPA has determined do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the 2008 ozone NAAQS.

The EPA is finalizing a FIP for each of the 22 states subject to this rule, having found that they failed to submit a complete good neighbor SIP (15 states) or having issued a final rule disapproving their good neighbor SIP (7 states). However, even after these FIPs take effect, any state included in this rule can submit a good neighbor SIP at any time that, if approved by the EPA, could replace the FIP for that state. Additionally, CSAPR provides states with the option to submit abbreviated SIPs to customize the methodology for allocating CSAPR NO_X ozone season allowances while participating in the ozone season trading program and the EPA is extending that approach in this rule.

The 22 states for which the EPA is promulgating FIPs to reduce interstate ozone transport as to the 2008 ozone NAAQS are listed in Table I.A–1.

TABLE I.A–1—LIST OF 22 COVERED STATES FOR THE 2008 8-HOUR OZONE NAAQS

State name
Alabama
Arkansas
Illinois
Indiana
Iowa
Kansas
Kentucky
Louisiana
Maryland
Michigan
Mississippi
Missouri
New Jersey
New York
Ohio
Oklahoma
Pennsylvania
Tennessee
Texas
Virginia
West Virginia
Wisconsin

The final CSAPR Update addresses collective contributions of ozone pollution from states in the eastern U.S. and builds on previous eastern-focused efforts to address collective contributions to interstate transport, including the NO_X SIP Call, the Clean Air Interstate Rule,[10] and the original CSAPR rules. The EPA is not finalizing FIPs to address interstate emission transport for western states, where there may be additional factors to consider in the EPA's and state's evaluations.

The EPA finds, in the final air quality modeling on which this rule is based, one state for which the EPA proposed a FIP in the proposed CSAPR Update rule, North Carolina, is not linked to any downwind nonattainment or maintenance receptors. Therefore, the EPA is not finalizing a FIP for North Carolina.

For 14 of the eastern states evaluated in this rule (Connecticut, Florida, Georgia, Maine, Massachusetts, Minnesota, Nebraska, New Hampshire, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, and Vermont), the EPA has determined that emissions from those states do not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. Accordingly, the EPA has determined that it need not require further emission reductions from sources in these states to address the good neighbor provision as to the 2008 ozone NAAQS.

Of the 22 states covered in this CSAPR Update, 21 states [11] have original CSAPR NO_X ozone season FIP requirements with respect to the 1997 ozone NAAQS. One state, Kansas, has newly added CSAPR NO_X ozone season FIP requirements in this action. For the 22 states affected by one of the FIPs finalized in this action, the EPA is promulgating new FIPs with EGU NO_X ozone season emission budgets to reduce interstate transport for the 2008 ozone NAAQS.

One state, Georgia, has an ongoing original CSAPR NO_X ozone season FIP requirement with respect to the 1997 ozone NAAQS, but the EPA has found that is does not contribute to interstate transport with respect to the 2008 ozone NAAQS. The EPA did not reopen comment on Georgia's interstate transport obligation with respect to the 1997 ozone NAAQS in this rulemaking, so Georgia's original CSAPR NO_X ozone season requirements (including its emission budget) continue unchanged.

In addition to reducing interstate ozone transport with respect to the 2008 ozone NAAQS, this rule also addresses the status of outstanding interstate ozone transport obligations with respect

[8] The term ''state'' has the same meaning as provided in CAA section 302(d) which specifically includes the District of Columbia.

[9] The states included in this finding of failure to submit are: Alabama, Arkansas, California, Florida, Georgia, Illinois, Iowa, Kansas, Maine, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Mexico, North Carolina, Oklahoma, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia, and West Virginia.

[10] 70 FR 25162 (May 12, 2005).

[11] Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

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to the 1997 ozone NAAQS. In the original CSAPR, the EPA promulgated FIPs for 25 states to address ozone transport with respect to the 1997 NAAQS. For 11 of these states,[12] the original CSAPR rulemakings quantified ozone season NO_X emission reductions that were not necessarily sufficient to eliminate all significant contribution to downwind nonattainment or interference with downwind maintenance of the 1997 ozone NAAQS. Relying on modeling completed for this final rule, this action finds that, with implementation of the original CSAPR NO_X ozone season emission budgets, emissions from ten of these states no longer significantly contribute to downwind nonattainment or interference with maintenance for the 1997 ozone NAAQS. The EPA further finds that, with implementation of the CSAPR Update NO_X ozone season emission budgets, emissions from these ten states also no longer significantly contribute to downwind nonattainment or interference with maintenance for the 1997 ozone NAAQS. With respect to Texas, the modeling shows that emissions from within the state no longer significantly contribute to downwind nonattainment or interference with maintenance for the 1997 ozone NAAQS even without implementation of the original CSAPR NO_X ozone season emission budget. Accordingly, sources in Texas will no longer be subject to the emissions budget calculated to address the 1997 ozone NAAQS. However, as described earlier, this rule finalizes a new emissions budget for Texas designed to address interstate transport with respect to the 2008 ozone NAAQS.

This action is also intended to address the portion of the July 28, 2015 opinion of the United States Court of Appeals for the District of Columbia (D.C. Circuit) remanding without vacatur 11 states' CSAPR phase 2 NO_X ozone season emission budgets. *EME Homer City Generation, L.P.,* v. *EPA,* No. 795 F.3d 118, 129–30, 138 (*EME Homer City II*). This action promulgates new NO_X ozone season budgets addressing interstate transport with respect to the 2008 ozone NAAQS that take effect in 2017, which replace the invalidated phase 2 budgets for 8 states, and also removes the remaining three states from the CSAPR NO_X ozone season trading program as a result of the EPA's finding that these three states do not significantly contribute to downwind nonattainment or interference with maintenance for the 2008 standard.[13]

The EPA acknowledges that, in *EME Homer City II,* the D.C. Circuit also remanded without vacatur the CSAPR phase 2 SO_2 emission budgets as to four states. 795 F.3d at 129, 138. This final rule does not address the remand of these CSAPR phase 2 SO_2 annual emission budgets. On June 27, 2016, the EPA released a memorandum outlining the agency's approach for responding to the D.C. Circuit's July 2015 remand of the CSAPR phase 2 SO_2 annual emission budgets for Alabama, Georgia, South Carolina and Texas. The memorandum can be found at *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf.*

On October 1, 2015, the EPA strengthened the ground-level ozone NAAQS, based on extensive scientific evidence about ozone's effects on public health and welfare.[14] While reductions achieved by this final rule will aid in attainment and maintenance of the 2015 standard, the CSAPR Update rule to reduce interstate emission transport with respect to the 2008 ozone NAAQS is a separate and distinct regulatory action and is not meant to address the CAA's good neighbor provision with respect to the 2015 ozone NAAQS final rule.

The EPA notes that the level of the annual $PM_{2.5}$ NAAQS was also revised after CSAPR was promulgated (78 FR 3086, January 15, 2013). However, this final rule does not address the 2012 $PM_{2.5}$ standard.[15]

B. Major Provisions

To reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), this rule further limits ozone season (May 1 through September 30) NO_X emissions from electric generating units (EGUs) in 22 eastern states using the same framework used by the EPA in developing the original CSAPR. The CSAPR framework provides a 4-step process to address the requirements of the good neighbor provision for ambient ozone or $PM_{2.5}$ standards: (1) Identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards (*i.e.,* NAAQS); (2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems; (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of a standard; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, reducing the identified upwind emissions via regional emission allowance trading programs. Each time the relevant NAAQS are revised, this process can be applied for the new NAAQS. In this final action, the EPA applies this 4-step CSAPR framework to update CSAPR with respect to the 2008 ozone NAAQS.

The EPA is aligning implementation of this rule with relevant attainment dates for the 2008 ozone NAAQS, as required by the D.C. Circuit's decision in *North Carolina* v. *EPA.*[16] The EPA's final 2008 Ozone NAAQS SIP Requirements Rule [17] established the attainment deadline of July 20, 2018 for ozone nonattainment areas currently designated as Moderate. Because the attainment date falls during the 2018 ozone season, the 2017 ozone season will be the last full season from which data can be used to determine attainment of the NAAQS by the July 20, 2018 attainment date. Therefore, consistent with the court's instruction in *North Carolina,* the EPA establishes emission budgets and implementation of these emission budgets starting with the 2017 ozone season.

In order to apply the first and second steps of the CSAPR 4-step framework to interstate transport for the 2008 ozone NAAQS, the EPA used air quality modeling to project ozone concentrations at air quality monitoring sites to 2017. The EPA updated this modeling for the final rule, using the most current complete dataset available, taking into account comments submitted on the August 2015 Air Quality Modeling NODA and on the CSAPR Update rule proposal. For the final rule, the EPA evaluated modeling

[12] Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, Tennessee, and Texas. (*See* CSAPR Final Rule, 76 FR at 48220, and the CSAPR Supplemental Rule, 76 FR at 80760, December 27, 2011).

[13] The EPA is promulgating new emission budgets that would replace the invalidated CSAPR phase 2 NO_X ozone season budgets for Iowa, Maryland, Michigan, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Virginia, West Virginia, and Wisconsin. The EPA is removing Florida, North Carolina, and South Carolina from the CSAPR ozone season NO_X trading program.

[14] 80 FR 65291 (October 26, 2015).

[15] The EPA issued a memo addressing CAA section 110(a)(2)(D)(i)(I) requirements for the 2012 $PM_{2.5}$ NAAQS, see "Information on the Interstate Transport 'Good Neighbor' Provision for the 2012 Fine Particulate Matter National Ambient Air Quality Standards under Clean Air Act section 110(a)(2)(D)(i)(I)," March 17, 2016.

[16] 531 F.3d 896, 911–12 (D.C. Cir. 2008) (holding that the EPA must coordinate interstate transport compliance deadlines with downwind attainment deadlines).

[17] 80 FR 12264, 12268; 40 CFR 51.1103.

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projections for air quality monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2008 ozone NAAQS. The EPA then uses air quality modeling to assess contributions from upwind states to these downwind receptors and evaluates these contributions relative to a screening threshold of 1 percent of the NAAQS. States with contributions that equal or exceed 1 percent of the NAAQS are identified as warranting further analysis for significant contribution to nonattainment or interference with maintenance. States with contributions below 1 percent of the NAAQS are considered to not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.[18]

To apply the third step of the 4-step CSAPR framework, the EPA quantified emission budgets that limit allowable emissions and represent the emission levels that remain after each state makes EGU NO_X emission reductions that are necessary to reduce interstate ozone transport for the 2008 NAAQS. To establish the CSAPR Update emission budgets, the EPA evaluated levels of uniform NO_X control stringency, represented by an estimated marginal cost per ton of NO_X reduced. The EPA applied the CSAPR multi-factor test to evaluate cost, available emission reductions, and downwind air quality impacts to determine the appropriate level of uniform NO_X control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. The EPA used this multi-factor assessment to gauge the extent to which emission reductions are needed, and to ensure those reductions do not represent over-control.

The multi-factor test generates a ''knee in the curve'' at a point where emission budgets reflect a control stringency with an estimated marginal cost of $1,400 per ton. This level of stringency in emission budgets represents the level at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized with respect to marginal cost. That is, the ratio of emission reductions to marginal cost and the ratio of ozone improvements to marginal cost are maximized relative to the other emission budget levels evaluated. The EPA finds that very cost-effective EGU NO_X reductions can make meaningful and timely improvements in downwind ozone air quality to address interstate ozone transport for the 2008 ozone NAAQS for the 2017 ozone season. Further, this evaluation shows that emission budgets reflecting the $1,400 per ton cost threshold do not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked or the 1 percent contribution threshold that triggered further evaluation. As a result, the EPA is finalizing EGU NO_X ozone season emission budgets developed using uniform control stringency represented by $1,400 per ton. The emission budgets that the EPA is finalizing in FIPs for the CSAPR Update rule are summarized in table I.B–1.

TABLE I.B–1—FINAL 2017 EGU NO_X OZONE SEASON EMISSION BUDGETS FOR THE CSAPR UPDATE RULE

[Ozone season NO_X tons]

State	CSAPR update rule 2017 * emission budgets
Alabama	13,211
Arkansas	12,048/9,210
Illinois	14,601
Indiana	23,303
Iowa	11,272
Kansas	8,027
Kentucky	21,115
Louisiana	18,639
Maryland	3,828
Michigan	17,023
Mississippi	6,315
Missouri	15,780
New Jersey	2,062
New York	5,135
Ohio	19,522
Oklahoma	11,641
Pennsylvania	17,952
Tennessee	7,736
Texas	52,301
Virginia	9,223
West Virginia	17,815
Wisconsin	7,915
22 State Region	316,464/313,626

* The EPA is finalizing CSAPR EGU NO_X ozone season emission budgets for Arkansas of 12,048 tons for 2017 and 9,210 tons for 2018 and subsequent control periods.

Our analysis shows that there is uncertainty regarding whether or not meaningful, cost-effective non-EGU emission reductions are achievable for the 2017 ozone season. Therefore, non-EGU reductions are not included in the final rule.

For most states, the EGU NO_X ozone season emission budgets finalized in this action represent a partial remedy to address interstate emission transport for the 2008 ozone NAAQS.[19] However, as stated in the proposal, the EPA believes that it is beneficial to implement, without further delay, EGU NO_X reductions that are achievable in the near term, particularly before the Moderate area attainment date of 2018. Generally, notwithstanding that additional reductions may be required to fully address the states' interstate transport obligations, the EGU NO_X emission reductions implemented by this final rule are needed for upwind states to eliminate their significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS and for downwind states with ozone nonattainment areas that are required to attain the standard by July 20, 2018.

To meet the fourth step of the four-step CSAPR framework (*i.e.,* implementation), the FIPs contain enforceable measures necessary to achieve the emission reductions in each state. The FIPs contained in this CSAPR Update require power plants in covered states (*i.e.,* states that significantly contribute to ozone nonattainment or interfere with maintenance of the ozone standard in the east) to participate in a CSAPR NO_X ozone season Group 2 allowance trading program. CSAPR's trading programs and the EPA's prior emission trading programs (*e.g.,* CAIR and the NO_X SIP Call) provide a proven implementation framework for achieving emission reductions. In addition to providing environmental certainty (*i.e.,* a cap on emissions), these programs also provide regulated sources with flexibility in choosing compliance strategies. By using the CSAPR allowance trading programs, the EPA is applying an implementation framework that was shaped by notice and comment in previous rulemakings and reflects the evolution of these programs in response to court decisions and practical experience gained by states, industry and the EPA. Further, this program is familiar to the EGUs that will be regulated under this rule, which means that monitoring, reporting, and compliance will continue as they are already conducted under CSAPR's current ozone season and annual programs.[20]

[18] As discussed further in section V, EPA's modeling showed that the following eastern states contribute below the 1 percent contribution threshold to downwind nonattainment or maintenance receptors: Connecticut, Florida, Georgia, Maine, Massachusetts, Minnesota, Nebraska, New Hampshire, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, and Vermont.

[19] The requirements for one state, Tennessee, will fully eliminate that state's significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS.

[20] One state, Kansas, will have a new CSAPR ozone season requirement. EGUs located in Kansas currently participate in the CSAPR NO_X and SO_2 annual programs. The remaining 22 states were

The CSAPR Update establishes two trading groups within the CSAPR NO_X ozone season allowance trading program—Group 1 for Georgia and Group 2 for the 22 CSAPR Update states. At this time, Georgia is the only state included in the CSAPR NO_X ozone season Group 1 trading program. The EPA will issue distinct allowances for these trading groups; CSAPR NO_X ozone season Group 1 allowances and CSAPR NO_X ozone season Group 2 allowances. Covered entities demonstrate compliance by holding and surrendering one allowance for each ton of NO_X emitted during the ozone season. In order to ensure that the CSAPR NO_X ozone season trading program implements emission reductions needed to meet the Clean Air Act's good neighbor requirements for the CSAPR Update states, the EPA finalizes a prohibition on allowance usage between Georgia and the CSAPR Update states. However, the EPA provides an option for Georgia to voluntarily adopt via SIP an emission budget that is commensurate with CSAPR Update emission budgets that could include Georgia in the Group 2 trading program with the CSAPR Update states. Implementation of Group 1 and Group 2 trading programs is substantially the same as the original CSAPR NO_X ozone season trading program. For states with continuing obligations to address interstate transport with respect to the 1997 ozone NAAQS as well as obligations under this rule with respect to the 2008 ozone NAAQS,[21] the EPA is coordinating the FIP requirements for the two NAAQS by providing that compliance with the 2008 ozone NAAQS FIP requirements simultaneously satisfies the state's transport obligations with respect to the less stringent 1997 ozone NAAQS. These states will therefore only be required to comply with the CSAPR NO_X ozone season Group 2 requirements.

For this CSAPR Update, the EPA considered whether, and to what extent, banked [22] 2015 and 2016 CSAPR NO_X ozone season allowances should be eligible for compliance in the CSAPR Update rule states. As proposed, the CSAPR Update finalizes a limit on the number of banked allowances carried over based on the need to assure that the CAA objective of the CSAPR Update is achieved. This approach transitions some allowances for compliance to further ensure feasibility of implementing the CSAPR Update rule. The EPA proposed to use turn-in ratios calculated using a formula—essentially the same formula that the EPA is finalizing in this rule. Specifically, the final rule establishes a one-time allowance conversion that transitions a limited number of banked vintage 2015 and 2016 allowances for compliance use in CSAPR Update states. This allowance conversion limits the number of banked allowances to 1.5 years of states' aggregated CSAPR variability limits (approximately 99,700 allowances) in order to ensure that implementation of the trading program will result in NO_X emission reductions sufficient to address significant contribution to nonattainment or interference with maintenance of downwind pollution with respect to the 2008 ozone NAAQS.

The compliance requirements of this final rule are in addition to existing, on-the-books EPA and state environmental regulations. To the extent that new, unplanned actions may also reduce EGU NO_X emissions within a state included in the CSAPR Update, whether for compliance with other environmental requirements or for other reasons, such actions would help the state comply with its good neighbor requirements. The final FIP compliance requirements begin with the 2017 ozone season and will continue for subsequent ozone seasons to ensure that upwind states included in this rule meet their Clean Air Act obligation to address interstate emission transport with respect to the 2008 ozone NAAQS for 2017 and future years. Even after the attainment deadline has passed, areas are required to continue to attain and maintain the NAAQS, and these good neighbor emission limits will ensure that future emissions are consistent with states' ongoing good neighbor obligations.

The EPA is finalizing revisions to the Code of Federal Regulations (CFR), specifically: 40 CFR part 97, subparts BBBBB and EEEEE (federal CSAPR NO_X ozone season trading programs); 40 CFR 52.38(b) (CSAPR NO_X ozone season FIP requirements and rules on replacing or modifying the FIP requirements through a SIP revision); state-specific subparts of 40 CFR part 52 for 25 states (descriptions for these states of FIP requirements and consequences of SIP revisions related to ozone season NO_X emissions); and 40 CFR part 78 (provisions addressing the scope of coverage of the administrative appeal procedures) to address interstate transport for the 2008 ozone NAAQS. In addition, as proposed, various minor corrections are being finalized to these CFR sections and other sections of parts 52, 78, and 97 relating to the CSAPR ozone season and annual trading programs.

The remainder of this preamble is organized as follows: Section III describes the EPA's legal authority for this action; section IV describes the human health and environmental context, the EPA's overall approach for addressing interstate transport through use of the CSAPR framework, and the EPA's response to the remand of certain CSAPR NO_X ozone season emission budgets; section V describes the air quality modeling platform and emission inventories that the EPA used in its assessment of downwind receptors of concern and upwind state ozone contributions to those receptors for the final rule; section VI describes the EPA's approach to quantify upwind state obligations in the form of final EGU NO_X emission budgets; section VII details the implementation requirements including key elements of the CSAPR allowance trading program and deadlines for compliance; section VIII describes the expected costs, benefits, and other impacts of this rule; section IX discusses changes to the existing regulatory text for the CSAPR FIPs and the CSAPR trading programs; and section X discusses the statutes and executive orders affecting this rulemaking. The preamble sections include certain significant comments and responses to comments as they pertain to the topic covered in each section.

C. Benefits and Costs

The rule will achieve near-term emission reductions from the power sector, lowering ozone season NO_X in 2017 by 61,000 tons, compared to 2017 projections without the rule.

Consistent with Executive Order 13563, ''Improving Regulation and Regulatory Review,'' the EPA has estimated the costs and benefits of the rule. Estimates here are subject to uncertainties discussed further in the Regulatory Impact Analysis (RIA) in the docket. The estimated net benefits of the rule at 3 percent and 7 percent discount rates are $460 million to $810 million and $450 million to $790 million (2011$), respectively. The non-monetized benefits include reduced ecosystem impacts and improved visibility. Discussion of the rule's costs and benefits is provided in preamble section VIII and in the RIA, which is found in the docket for this final rule. The EPA's estimate of the rule's costs

included in the original CSAPR ozone season program as to the 1997 ozone NAAQS.

[21] Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, and Tennessee.

[22] Allowances that were not used for compliance and were saved for use in a later compliance period.

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and quantified benefits is summarized in Table I.C–1.

TABLE I.C–1—SUMMARY OF COMPLIANCE COSTS, MONETIZED BENEFITS, AND MONETIZED NET BENEFITS OF THE FINAL RULE FOR 2017
[2011$]

Description	Impacts (benefits at 3% discount rate) ($ millions)	Impacts (benefits at 7% discount rate) ($ millions)
Annualized Compliance Costs [a]	68	68
Monetized benefits [b]	530 to 880	520 to 860
Monetized Net benefits (benefits-costs)	460 to 810	450 to 790

[a] The annualized compliance costs estimate is used as a proxy for the total annualized social costs. These costs are determined using the 4.77% percent discount rate from the electricity sector model used for this analysis and are rounded to two significant figures. The annualized compliance costs presented here reflect the cost to the electricity sector of complying with the FIPs. These costs do not include monitoring, recordkeeping, and reporting costs, which are reported separately. See Chapter 4 of the RIA for this final rule for details and explanation.

[b] Total monetized health benefits are estimated at 3 percent and 7 percent discount rates and are rounded to two significant figures. The total monetized benefits reflect the human health benefits associated with reducing exposure to ozone and $PM_{2.5}$. It is important to note that the monetized benefits and co-benefits include many but not all health effects associated with pollution exposure. Benefits are shown as a range reflecting studies from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Zanobetti and Schwartz (2008).

II. General Information

A. To whom does this final action apply?

This rule affects EGUs, and regulates the following groups:

Industry group	NAICS *
Fossil fuel-fired electric power generation	221112

* North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware will be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in 40 CFR 97.504 and 97.804. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

III. Legal Authority

A. The EPA's Statutory Authority for the Final Rule

The statutory authority for this final action is provided by the CAA as amended (42 U.S.C. 7401 *et seq.*). Specifically, sections 110 and 301 of the CAA provide the primary statutory underpinnings for this rule. The most relevant portions of section 110 are subsections 110(a)(1), 110(a)(2), and 110(a)(2)(D)(i)(I), and 110(c)(1).

Section 110(a)(1) provides that states must make SIP submissions ''within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof),'' and that these SIP submissions are to provide for the ''implementation, maintenance, and enforcement'' of such NAAQS.[23] The statute directly imposes on states the duty to make these SIP submissions, and the requirement to make the submissions is not conditioned upon the EPA taking any action other than promulgating a new or revised NAAQS.[24]

The EPA has historically referred to SIP submissions made for the purpose of satisfying the applicable requirements of CAA sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' submissions. Section 110(a)(1) addresses the timing and general requirements for infrastructure SIP submissions, and section 110(a)(2) provides more details concerning the required content of these submissions. It includes a list of specific elements that ''[e]ach such plan'' submission must address.[25] All states, regardless of whether the state includes areas designated as nonattainment for the relevant NAAQS, must have SIPs that meet the applicable requirements of section 110(a)(2), including provisions of section 110(a)(2)(D)(i)(I) described later and that are the focus of this rule.

Section 110(c)(1) requires the Administrator to promulgate a FIP at any time within 2 years after the Administrator: (1) Finds that a state has failed to make a required SIP submission, (2) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C), or (3) disapproves a SIP submission, unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.[26]

Section 110(a)(2)(D)(i)(I), also known as the ''good neighbor provision,'' provides the basis for this action. It requires that each state SIP shall include provisions sufficient to ''prohibit[] . . . any source or other type of emissions activity within the State from emitting any air pollutants in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' [27]

The EPA has previously issued three rules interpreting and clarifying the requirements of section 110(a)(2)(D)(i)(I) for states in the eastern half of the United States. These rules, and the associated court decisions addressing these rules, provide important guidance regarding the requirements of section 110(a)(2)(D)(i)(I).

The NO_X SIP Call, promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS and the 1997 8-hour ozone NAAQS.[28] The rule required 22 states and the District of Columbia to amend their SIPs and limit NO_X emissions that contribute to ozone nonattainment. The EPA set a NO_X ozone season budget for each covered state, essentially a cap on ozone season NO_X emissions in the state. Sources in the covered states were given the option to participate in a regional cap-and-trade program, known as the NO_X Budget Trading Program (NBP). The NO_X SIP Call was largely upheld by the D.C. Circuit in *Michigan*

[23] 42 U.S.C. 7410(a)(1).

[24] *See EPA* v. *EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1601 (2014).

[25] The EPA's general approach to infrastructure SIP submissions is explained in greater detail in individual notices acting or proposing to act on state infrastructure SIP submissions and in guidance. *See, e.g.,* Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2) (Sept. 2013).

[26] 42 U.S.C. 7410(c)(1).

[27] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[28] 63 FR 57356 (Oct. 27, 1998).

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v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001).

The Clean Air Interstate Rule (CAIR), promulgated in 2005, addressed both the 1997 $PM_{2.5}$ and the 1997 ozone standards under the good neighbor provision.[29] CAIR required SIP revisions in 28 states and the District of Columbia to ensure that certain emissions of sulfur dioxide (SO_2) and/or NO_X—important precursors of regionally transported $PM_{2.5}$ (SO_2 and NO_X) and ozone (NO_X)—were prohibited. Like the NO_X SIP Call, states were given the option to participate in a regional cap-and-trade program to satisfy their SIP obligations. When the EPA promulgated the final CAIR in May 2005, the EPA also issued a national rule finding that states had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 $PM_{2.5}$ and the 1997 ozone NAAQS. Those states were required by the CAA to have submitted good neighbor SIPs for those standards by July 2000.[30] These findings of failure to submit triggered a 2-year clock for the EPA to issue FIPs to address interstate transport, and on March 15, 2006, the EPA promulgated FIPs to ensure that the emission reductions required by CAIR would be achieved on schedule.[31] CAIR was remanded to the EPA by the D.C. Circuit in *North Carolina,* 531 F.3d 896 (D.C. Cir. 2008), *modified on reh'g,* 550 F.3d 1176. For more information on the legal considerations of CAIR and the D.C. Circuit holding in *North Carolina,* refer to the preamble of the original CSAPR rule.[32]

In 2011, the EPA promulgated the original CSAPR to address the issues raised by the remand of CAIR and additionally to address the good neighbor provision for the 2006 $PM_{2.5}$ NAAQS.[33] CSAPR requires 28 states to reduce SO_2 emissions, annual NO_X emissions, and/or ozone season NO_X emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards. To accomplish implementation aligned with the applicable attainment deadlines, the EPA promulgated FIPs for each of the 28 states covered by CSAPR. The FIPs implement regional cap-and-trade programs to achieve the necessary emission reductions. States can submit good neighbor SIPs at any time that, if approved by the EPA, would replace the CSAPR FIP for that state.[34] As discussed later, CSAPR was the subject of decisions by both the D.C. Circuit and the Supreme Court, which largely upheld the rule.

On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012), vacating CSAPR and holding, among other things, that states had no obligation to submit good neighbor SIPs until the EPA had first quantified each state's good neighbor obligation.[35] The implication of this decision was that the EPA did not have authority to promulgate the CSAPR FIPs as a result of states' failure to submit or the EPA's disapproval of good neighbor SIPs. The D.C. Circuit also held that the EPA erred in apportioning upwind emission reduction obligations using uniform cost thresholds, and that such approach may result in unnecessary over-control.[36] The EPA sought review, first with the D.C. Circuit *en banc* and then with the Supreme Court. While the D.C. Circuit declined to consider the EPA's appeal *en banc,*[37] on January 23, 2013, the Supreme Court granted the EPA's petition for certiorari.[38]

On April 29, 2014, the Supreme Court issued a decision reversing the D.C. Circuit's *EME Homer City* opinion on CSAPR and held, among other things, that under the plain language of the CAA, states must submit SIPs addressing the good neighbor provision within 3 years of promulgation of a new or revised NAAQS, regardless of whether the EPA first provides guidance, technical data or rulemaking to quantify the state's obligation.[39] Thus, the Supreme Court affirmed that states have an obligation in the first instance to address the good neighbor provision after promulgation of a new or revised NAAQS, a holding that also applies to states' obligation to address interstate transport for the 2008 ozone NAAQS. The Court also reversed the D.C. Circuit's holding that the EPA's use of cost to apportion upwind states' emission reduction obligations was impermissible, finding that the EPA's approach was a ''permissible construction of the statute.'' [40] The Supreme Court remanded the litigation to the D.C. Circuit for further proceedings.

Finally, on July 28, 2015, the D.C. Circuit issued its opinion on CSAPR regarding the remaining legal issues raised by the petitioners on remand from the Supreme Court, *EME Homer City II,* 795 F.3d 118. This decision largely upheld the EPA's approach to addressing interstate transport in CSAPR, leaving the rule in place and affirming the EPA's interpretation of various statutory provisions and the EPA's technical decisions. The decision also remanded the rule without vacatur for reconsideration of the EPA's emission budgets for certain states. In particular and as discussed in section IV, the court declared invalid the CSAPR phase 2 NO_X ozone season emission budgets of 11 states, holding that those budgets over-control with respect to the downwind air quality problems to which those states were linked for the 1997 ozone NAAQS. The court's decision explicitly applies to 11 states: Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, and West Virginia. *Id.* at 129–30, 138. The court also remanded without vacatur the CSAPR phase 2 SO_2 annual emission budgets for four states (Alabama, Georgia, South Carolina, and Texas) for reconsideration. *Id.* at 129, 138. The court instructed the EPA to act ''promptly'' in addressing these issues on remand. *Id.* at 132.[41]

Section 301(a)(1) of the CAA also gives the Administrator of the EPA general authority to prescribe such regulations as are necessary to carry out her functions under the Act.[42] Pursuant to this section, the EPA has authority to clarify the applicability of CAA requirements. In this action, among other things, the EPA is clarifying the applicability of section 110(a)(2)(D)(i)(I) by identifying NO_X emissions in certain states that must be prohibited pursuant

[29] 70 FR 25162 (May 12, 2005).

[30] 70 FR 21147 (May 12, 2005).

[31] 71 FR 25328 (April 28, 2006).

[32] 76 FR 48208, 48217 (Aug. 8, 2011).

[33] 76 FR 48208.

[34] Alabama has submitted, and EPA has approved, a SIP revision that replaces the CSAPR FIPs for the annual trading programs in Alabama. 81 FR 59869 (Aug. 31, 2016).

[35] *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7, 31 (D.C. Cir. 2012) (*EME Homer City I*).

[36] *Id.* at 23–27.

[37] *EME Homer City Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir. January 24, 2013), ECF No. 1417012 (denying the EPA's motion for rehearing en banc).

[38] *EPA* v. *EME Homer City Generation, L.P.,* 133 S. Ct. 2857 (2013) (granting the EPA's and other parties' petitions for certiorari).

[39] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584, 1600–01 (2014).

[40] *Id.* at 1606–07.

[41] In 2011, EPA finalized a supplemental rule that added five states to the CSAPR NO_X ozone season trading program, 76 FR 80760 (Dec. 27, 2011). In 2012, the EPA also finalized two rules making certain revisions to CSAPR. 77 FR 10324 (Feb. 21, 2012); 77 FR 34830 (June 12, 2012). Various petitioners filed legal challenges to these rules in the D.C. Circuit. *See Public Service Company of Oklahoma* v. *EPA,* No. 12–1023 (D.C. Cir., filed Jan. 13, 2012); *Wisconsin Public Service Corp.* v. *EPA,* No. 12–1163 (D.C. Cir., filed Apr. 6, 2012); *Utility Air Regulatory Group* v. *EPA,* No. 12–1346 (D.C. Cir., filed Aug. 9, 2012). These cases were held in abeyance during the pendency of the litigation in *EME Homer City,* and remain pending in the D.C. Circuit as of the date of signature of this rule.

[42] 42 U.S.C. 7601(a)(1).

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to this section with respect to the 2008 ozone NAAQS.

In particular, the EPA is using its authority under sections 110 and 301 to promulgate FIPs that establish or revise EGU NO_X ozone season emission budgets for 22 eastern states to mitigate their significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS in another state.[43] The EPA is also responding to the court's remand in *EME Homer City II* with respect to the remanded NO_X ozone season emission budgets.

B. FIP Authority for Each State Covered by the Final Rule

As discussed previously, all states have an obligation to submit SIPs that address the applicable requirements of CAA section 110(a)(2) within 3 years of promulgation of a new or revised NAAQS. With respect to the 2008 ozone NAAQS, states were required to submit SIPs addressing the good neighbor provision by March 12, 2011. If the EPA finds that a state has failed to submit a SIP to meet its statutory obligation to address section 110(a)(2)(D)(i)(I) or if the EPA disapproves a good neighbor SIP, then the EPA has not only the authority but the obligation, pursuant to section 110(c)(1), to promulgate a FIP to address the CAA requirement no later than 2 years after the finding or disapproval.

On July 13, 2015, the EPA published a rule finding that 24 states failed to make complete submissions that address the requirements of section 110(a)(2)(D)(i)(I) related to the interstate transport of pollution as to the 2008 ozone NAAQS. *See* 80 FR 39961 (July 13, 2015) (effective August 12, 2015). The finding action triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for these states by August 12, 2017. The states included in this finding of failure to submit are: Alabama, Arkansas, California, Florida, Georgia, Illinois, Iowa, Kansas, Maine, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Mexico, North Carolina, Oklahoma, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia, and West Virginia.

Several additional eastern states—Connecticut, Delaware, Indiana, Kentucky, Louisiana, Maryland, Nebraska, New Jersey, New York, North Dakota, Ohio, Rhode Island, South Dakota, Texas, Wisconsin, and the District of Columbia—had previously submitted SIPs to address the requirements of section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Since the EPA issued the findings notice, the agency has also received a SIP submission addressing the good neighbor provision for the 2008 ozone NAAQS from the states of Maine, New Hampshire, North Carolina, and Vermont. Maryland and New Jersey subsequently withdrew their good neighbor SIP submittals addressing the 2008 ozone standard. The EPA issued separate notices finding that Maryland and New Jersey failed to make complete submissions that address the requirements of section 110(a)(2)(D)(i)(I) related to the interstate transport of pollution as to the 2008 ozone NAAQS. *See* 81 FR 47040 (July 20, 2016) (Maryland, effective August 19, 2016); 81 FR 38963 (June 15, 2016) (New Jersey, effective July 15, 2016). The finding actions triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for Maryland by August 19, 2018 and New Jersey by July 15, 2018.

To the extent that the EPA had not finalized action on these SIPs at proposal, the states were encouraged to evaluate their submissions in light of the information provided in the proposal with respect to interstate ozone transport for the 2008 ozone NAAQS. The EPA has finalized disapproval or partial disapproval of the good neighbor SIPs from Indiana, Kentucky, Louisiana, New York, Ohio, Texas and Wisconsin,[44] triggering the EPA's authority and obligation to promulgate FIPs that implement the requirements of the good neighbor provision for those states. The EPA has approved good neighbor SIPs addressing the 2008 ozone standard submitted by Nebraska, North Dakota, and South Dakota. The EPA has not yet taken final action to approve or disapprove the SIPs submitted by Connecticut, Delaware, the District of Columbia, Maine, New Hampshire, North Carolina, Rhode Island, and Vermont. However, the EPA is not finalizing FIPs as to these states in this action. The EPA will review and act upon these states' SIPs in separate, future actions.

Comment: Some commenters have questioned the EPA's authority to propose FIPs for certain states before the EPA has either issued findings of failure to submit good neighbor SIPs or taken final action to approve or disapprove pending good neighbor SIPs submitted by those states. Commenters state that the EPA's development of FIPs prior to taking those actions upsets the balance of state and federal authority. Some commenters state that this approach is inconsistent with the sequencing of events envisioned by Congress in CAA section 110(c). Another commenter contends that the CAA contemplates that states should have an opportunity to correct any problems with its SIP in a timely fashion and avoid imposition of a FIP. The commenter states that, until the EPA proposes to disapprove a state's SIP, the state does not know what corrections would be necessary.

One commenter states that the Supreme Court's decision in *EPA* v. *EME Homer City Generation* means that the EPA may issue a FIP if more than two years have elapsed since the EPA found the state's SIP was inadequate. The commenter suggests that states should be given the opportunity to submit a SIP after the EPA establishes a state budget before a FIP is implemented. The commenter states that the EPA adhered to the CAA in prior transport rulemakings like the NO_X SIP Call and CAIR by allowing states to decide how to meet budgets quantified by the EPA.

Response: The EPA disagrees with commenters' contention that we cannot propose a FIP for a state prior to taking final action on the state's SIP. CAA section 110(c) provides that the EPA ''shall promulgate a [FIP] *at any time* within two years after'' the EPA either finds that a state has failed to make a required submission or disapproves a SIP, in whole or in part. As the Supreme Court confirmed in *EPA* v. *EME Homer City Generation,* ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' 134 S. Ct. at 1601.

The EPA's proposal was not the ''promulgation'' of a FIP. Rather, the EPA is only finalizing FIPs for those states for which the EPA has either made a finding of failure to submit a SIP addressing the state's good neighbor obligation as to the 2008 ozone NAAQS or for which the EPA disapproved the state's good neighbor SIP. Accordingly, consistent with section 110(c), the EPA is only promulgating FIPs for those states that the EPA found have failed to address the statutory SIP obligation.

The EPA also disagrees that it was required to provide states with an opportunity to submit a SIP addressing the budgets calculated in this rule

[43] One state, Kansas, will have a new CSAPR ozone season requirement under this final rule. The remaining 21 states were included in the original CSAPR ozone season program as to the 1997 ozone NAAQS.

[44] The EPA has finalized a partial disapproval of the good neighbor SIP from the state of Wisconsin. The EPA partially approved Wisconsin's SIP as to the state's significant contribution to nonattainment and partially disapproved as to the state's interference with maintenance of the 2008 ozone NAAQS. *See* 81 FR 53309 (August 12, 2013).

before promulgating a FIP. The Supreme Court clearly held that the Act does not ''condition the duty to promulgate a FIP on EPA's having first quantified an upwind State's good neighbor obligations.'' 134 S. Ct. at 1601. Nor does the Act ''require EPA to furnish upwind States with information of any kind about their good neighbor obligations before a FIP issues.'' *Id.* While the EPA has taken a different approach in some prior rulemakings by providing states with an opportunity to submit a SIP after the EPA quantified the states' budgets, the circumstances of this rule require a different approach. As discussed in more detail earlier, it is important for the EPA to assure that emission reductions are achieved, to the extent feasible, by the 2017 ozone season in order to assist downwind areas with meeting the July 20, 2018 attainment deadline for Moderate nonattainment areas. If the EPA were to permit states an opportunity to develop and submit state plans to address the emission reductions required by this rule before imposing a federal plan, the EPA could not ensure that these emission reductions would be achieved in a timely manner. However, states may submit SIPs to replace the FIPs promulgated in this final rule at any time. Some types of SIPs that a state might consider are outlined in more detail later in section VII.

In addition to the agency's general FIP authority and the comments received on that issue, there is a unique issue related to the EPA's FIP obligation for Kentucky. On March 7, 2013, the EPA finalized action on the State of Kentucky's SIP submission addressing, among other things, the good neighbor provision requirements for the 2008 ozone NAAQS.[45] The EPA disapproved the submission as to the good neighbor requirements. In the notice, the EPA explained that the disapproval of the good neighbor portion of the state's infrastructure SIP submission did not trigger a mandatory duty for the EPA to promulgate a FIP to address these requirements.[46] Citing the D.C. Circuit's decision *EME Homer City I,* the EPA explained that the court concluded states have no obligation to make a SIP submission to address the good neighbor provision for a new or revised NAAQS until the EPA first defines a state's obligations pursuant to that section.[47] Therefore, because a good neighbor SIP addressing the 2008 ozone standard was not at that time required, the EPA indicated that its disapproval action would not trigger an obligation for the EPA to promulgate a FIP to address the interstate transport requirements.[48]

On April 30, 2013, the Sierra Club filed a petition for review of the EPA's action in the United States Court of Appeals for the Sixth Circuit based on the agency's conclusion that the FIP clock was not triggered by the disapproval of Kentucky's good neighbor SIP.[49] Subsequently, on April 29, 2014, the Supreme Court issued a decision reversing and vacating the D.C. Circuit's decision in *EME Homer City.* Following the Supreme Court decision, the EPA requested, and the Sixth Circuit granted, vacatur and remand of the portion of the EPA's final action on Kentucky's good neighbor SIP that determined that the FIP obligation was not triggered by the disapproval.[50]

In this document, the EPA is correcting the portion of the Kentucky disapproval notice indicating that the FIP clock would not be triggered by the SIP disapproval. The EPA believes that the EPA's obligation to develop a FIP was triggered on the date of the judgment issued by the Supreme Court in *EPA* v. *EME Homer City Generation,* June 2, 2014, and the EPA is obligated to issue a FIP at any time within two years of that date. The EPA does not believe that the FIP obligation was triggered as of the date of the SIP disapproval because the controlling law as of that date was the D.C. Circuit decision in *EME Homer City I,* which held that states had no obligation to submit a SIP and the EPA had no authority to issue a FIP until the EPA first quantified each state's emission reduction obligation under the good neighbor provision. Accordingly, the most reasonable conclusion is that the EPA's FIP obligation was triggered when the Supreme Court clarified the state and federal obligations with respect to the good neighbor provision. Thus, the EPA finds that the FIP obligation was triggered as of June 2, 2014, and that the EPA was obligated to promulgate a FIP that corrects the deficiency by June 2, 2016.

[45] 78 FR 14681 (March 7, 2013).

[46] *Id.* at 14683.

[47] *Id.*

[48] *Id.*

[49] *Sierra Club* v. *EPA,* Case No. 13–3546 (6th Cir., filed Apr. 30, 2013).

[50] Order, *Sierra Club* v. *EPA,* Case No. 13–3546, Document No. 74–1 (Mar. 13, 2015).

IV. Air Quality Issues Addressed and Overall Approach for the Final Rule

A. The Interstate Transport Challenge Under the 2008 Ozone Standard

1. Background on the Nature of the Interstate Ozone Transport Problem

Interstate transport of NO_X emissions poses significant challenges with respect to attaining the 2008 ozone NAAQS in the eastern U.S. and thus presents a threat to public health and welfare. The following sections discuss the nature and sources of ozone, how ozone is transported in the atmosphere and across state boundaries, and ozone's impacts on human health and the environment.

a. *Nature of ozone and the Ozone NAAQS.* Ground-level ozone is not emitted directly into the air, but is a secondary air pollutant created by chemical reactions between oxides of nitrogen (NO_X), carbon monoxide (CO), methane (CH_4), and non-methane volatile organic compounds (VOCs) in the presence of sunlight. Emissions from electric utilities, industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major anthropogenic sources of ozone precursors. The potential for ground-level ozone formation increases during periods with warmer temperatures and stagnant air masses; therefore ozone levels are generally higher during the summer months.[51] Ground-level ozone concentrations and temperature are highly correlated in the eastern U.S. with observed ozone increases of 2–3 ppb per degree Celsius reported.[52] Increased temperatures may also increase emissions of volatile man-made and biogenic organics and can indirectly increase anthropogenic NO_X emissions as well (*e.g.,* increased electricity generation to power air conditioning).

The 2008 primary and secondary ozone standards are both 75 ppb as an 8-hour maximum level. Specifically, the standards require that an area may not exceed 75 ppb using the 3-year average of the fourth highest 24-hour maximum 8-hour rolling average ozone concentration.

b. *Ozone transport.* Precursor emissions can be transported downwind directly or, after transformation in the atmosphere, as ozone. Studies have

[51] Rasmussen, D.J. *et al.* (2011) Ground-level ozone-temperature relationships in the eastern US: A monthly climatology for evaluating chemistry-climate models. Atmospheric Environment 47: 142–153.

[52] Bloomer, B.J., J.W. Stehr, C.A. Piety, R.J. Salawitch, *and* R.R. Dickerson (2009), Observed relationships of ozone air pollution with temperature and emissions, Geophys. Res. Lett., 36, *L09803*.

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established that ozone formation, atmospheric residence, and transport occurs on a regional scale (*i.e.,* hundreds of miles) over much of the eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas. As a result of ozone transport, in any given location, ozone pollution levels are impacted by a combination of local emissions and emissions from upwind sources. The transport of ozone pollution across state borders compounds the difficulty for downwind states in meeting health-based air quality standards (*i.e.,* NAAQS). Numerous observational studies have demonstrated the transport of ozone and its precursors and the impact of upwind emissions on high concentrations of ozone pollution. Bergin et al., for example, examined the impacts of statewide emissions of NO_X, SO_2, and VOCs on concentrations of ozone and fine particulate matter in the eastern U.S. They found on average 77 percent of each state's ground-level ozone is produced by precursor emissions from upwind states.[53] Liao et al., showed the impacts of interstate transport of anthropogenic NO_X and VOC emissions on peak ozone formation in 2007 in the Mid-Atlantic U.S. Results suggest reductions in anthropogenic NO_X emissions from EGU and non-EGU sources from the Great Lakes region as well as northeastern and southeastern U.S. would be effective for decreasing area-mean peak ozone concentrations in the Mid-Atlantic.[54]

The EPA has previously concluded in the NO_X SIP Call, CAIR, and CSAPR that, for reducing regional-scale ozone transport, a NO_X control strategy is effective. While substantial progress has been made in reducing ozone in many urban areas, regional-scale ozone transport is still an important component of peak ozone concentrations during the summer ozone season. Model assessments have looked at impacts on peak ozone concentrations after potential emission reduction scenarios for NO_X and VOCs for NO_X-limited and VOC-limited areas. For example, Jiang and Fast concluded that NO_X emission reductions strategies would be effective in lowering ozone mixing ratios in urban areas and Liao et al. showed NO_X reductions would reduce peak ozone concentrations in non-attainment areas in the Mid-Atlantic (*i.e.* a 10 percent reduction in EGU and non-EGU NO_X emissions would result in approximately a 6 ppb reduction in peak ozone concentrations in Washington, DC).[55] Assessments of ozone conducted for the October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone (EPA–452/R–15–007) also show the importance of NO_X emissions on ozone transport. This analysis is in the docket for this rule and also can be found in the docket for the 2015 ozone NAAQS, Docket No. EPA–HQ–OAR–2013–0169–0057.

Further, studies have found that EGU NO_X emission reductions, particularly, can be effective in reducing ozone pollution as quantified by the form of the 2008 ozone standard, 8-hour peak concentrations. Specifically, studies have found that EGU NO_X emission reductions can be effective in reducing the upper end of the cumulative ozone distribution in the summer on a regional scale.[56] Analysis of air quality monitoring data trends shows reductions in summertime ozone concurrent with implementation of EGU NO_X reduction programs.[57] Gilliland et al. presented reductions in observed versus modeled ozone concentrations in the eastern U.S. downwind from major NO_X sources. The results showed significant reductions in ozone concentrations (10–25 percent) from observed measurements (CASTNET and AQS) [58] between 2002 and 2005, linking reductions in EGU NO_X emissions from upwind states with ozone reductions downwind of the major source areas.[59] Another study shows that EGU NO_X emissions can contribute between 5 ppb and 25 ppb to average 8-hour peak ozone concentrations in Mid-Atlantic metropolitan statistical areas.[60] Additionally, Gégo et al. showed that ground-level ozone concentrations were significantly reduced after the NO_X SIP Call in regions downwind of major EGUs in the Ohio River Valley.[61]

Previous regional ozone transport efforts, including the NO_X SIP Call, CAIR, and CSAPR, required ozone season NO_X reductions from EGUs to address interstate transport of ozone. The EPA has taken comment on regulating EGU NO_X emissions to address interstate ozone transport in the notice-and-comment process for these rulemakings. The EPA received no significant adverse comments in any of these earlier proposals regarding the rules' focus on ozone season EGU NO_X reductions to address interstate ozone transport. Further, many comments received on the proposed CSAPR Update encouraged the EPA to seek further EGU NO_X reductions to address interstate transport for the 2008 ozone NAAQS. As described later in this document, the EPA's analysis finds that the power sector continues to be capable of making NO_X reductions that reduce interstate transport with respect to ground-level ozone.

c. *Health and environmental effects.* Exposure to ambient ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. In ecosystems, ozone exposure causes visible foliar injury, decreases plant growth, and affects ecosystem community composition. For more information on the human health and welfare and ecosystem effects associated with ambient ozone exposure, see the EPA's October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone (EPA–452/R–15–007) in the docket for this rule and can be also found in the docket for the 2015 ozone NAAQS, Docket No. EPA–HQ–OAR–2013–0169–0057.

[53] Bergin, M.S. *et al.* (2007) Regional air quality: local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[54] Liao, K. *et al.* (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[55] Jiang, G.; Fast, J.D. (2004) Modeling the effects of VOC and NO_X emission sources on ozone formation in Houston during the TexAQS 2000 field campaign. Atmospheric Environment 38: 5071–5085.

[56] Hidy, G.M. and Blanchard C.L. (2015) Precursor reductions and ground-level ozone in the Continental United States. J. of Air & Waste Management Assn. 65, 10.

[57] Simon, H. *et al.* (2015) Ozone trends across the United States over a period of decreasing NO_X and VOC emissions. Environmental Science & Technology 49, 186–195.

[58] CASTNET is the EPA's Clean Air Status and Trends Network. AQS is the EPA's Air Quality System.

[59] Gilliland, A.B. *et al.* (2008) Dynamic evaluation of regional air quality models: Assessing changes in O_3 stemming from changes in emissions and meteorology. Atmospheric Environment 42: 5110–5123.

[60] Summertime Zero-Out Contributions of regional NO_X and VOC emissions to modeled 8-hour ozone concentrations in the Washington, DC, Philadelphia, PA, and New York City MSAs.

[61] Gégo *et al.* (2007) Observation-based assessment of the impact of nitrogen oxides emissions reductions on O_3 air quality over the eastern United States. J. of Applied Meteorology and Climatology 46: 994–1008.

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2. Events Affecting Application of the Good Neighbor Provision for the 2008 Ozone NAAQS

On March 12, 2008, the EPA promulgated a revision to the NAAQS, lowering both the primary and secondary standards to 75 ppb. *See* National Ambient Air Quality Standards for Ozone, Final Rule, 73 FR 16436 (March 27, 2008). These revisions of the NAAQS, in turn, triggered a 3-year deadline of March 12, 2011, for states to submit SIP revisions addressing infrastructure requirements under CAA sections 110(a)(1) and 110(a)(2), including the good neighbor provision. During this 3-year SIP development period, on September 16, 2009, the EPA announced [62] that it would reconsider the 2008 ozone NAAQS. To reduce the workload for states during the interim period of reconsideration, the EPA also announced its intention to propose staying implementation of the 2008 standards with respect to a number of the requirements. On January 6, 2010, the EPA proposed to revise the 2008 NAAQS for ozone from 75 ppb to a level within the range of 60 to 70 ppb. *See* 75 FR 2938 (January 19, 2010). The EPA indicated its intent to issue final standards based upon the reconsideration by summer 2011.

On August 8, 2011, the EPA published the original CSAPR, in response to the D.C. Circuit's remand of the EPA's prior federal transport rule, CAIR. *See* 76 FR 48208 (August 8, 2011). The original CSAPR addressed ozone transport under the 1997 ozone NAAQS, but did not address the 2008 ozone standard, because the 2008 ozone NAAQS was under reconsideration when CSAPR was finalized.

On September 2, 2011, consistent with the direction of the President, the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget returned the draft final 2008 ozone rule the EPA had developed upon reconsideration to the agency for further consideration.[63] In view of that action and the timing of the agency's ongoing periodic review of the ozone NAAQS required under CAA section 109 (as announced on September 29, 2008), the EPA decided to coordinate further proceedings on its voluntary reconsideration of the 2008 ozone standards with its ongoing periodic review of the ozone NAAQS.[64] Implementation for the original 2008 ozone standards was renewed. However, a number of legal developments pertaining to the EPA's promulgation of the original CSAPR created uncertainty surrounding the EPA's statutory interpretation and implementation of the good neighbor provision.

On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA* addressing several legal challenges to CSAPR and holding, among other things, that states had no obligation to submit good neighbor SIPs until the EPA had first quantified each state's good neighbor obligation.[65] According to that decision, the submission deadline for good neighbor SIPs under the CAA would not necessarily be tied to the promulgation of a new or revised NAAQS. While the EPA disagreed with this interpretation of the statute and sought review of the decision in the D.C. Circuit and the U.S. Supreme Court, the EPA complied with the D.C. Circuit's ruling during the pendency of its appeal. In particular, the EPA indicated that, consistent with the D.C. Circuit's opinion, it would not at that time issue findings that states had failed to submit good neighbor SIPs for the 2008 ozone NAAQS.[66]

On January 23, 2013, the Supreme Court granted the EPA's petition for certiorari.[67] On April 29, 2014, the Supreme Court reversed the D.C. Circuit's *EME Homer City* opinion on CSAPR and held, among other things, that under the plain language of the CAA, states must submit SIPs addressing the good neighbor provision within 3 years of promulgation of a new or revised NAAQS, regardless of whether the EPA first provides guidance, technical data, or rulemaking to quantify the state's obligation.[68] Thus, the Supreme Court affirmed that states have an obligation in the first instance to address the good neighbor provision after promulgation of a new or revised NAAQS, a holding that also applies to the states' obligation to address transport for the 2008 ozone NAAQS.

States were therefore required to submit SIPs addressing the good neighbor provision with respect to the 2008 ozone NAAQS by March 12, 2011. Under the Supreme Court's holding, to the extent that states have failed to submit SIPs to meet this statutory obligation or the EPA has disapproved SIPs, then the EPA has not only the authority, but the obligation, to promulgate FIPs to address the CAA requirement.

B. Approach To Address Ozone Transport Under the 2008 Ozone NAAQS via FIPs

1. Requiring Emission Reductions From Upwind States

As described in section IV.A.1.b, the EPA finds that upwind EGU emission reductions are generally effective at reducing interstate transport of ozone pollution. And as described in section VI, with respect to this rule, the EPA finds that upwind emission reductions are achievable and will result in important and meaningful decreases in harmful downwind ozone pollution.

At the same time, the EPA also notes that section 110(a)(2)(D)(i)(I) of the CAA only requires upwind states to prohibit emissions that will significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states. It does not shift to upwind states the full responsibility for ensuring that all areas in downwind states attain and maintain the NAAQS. Downwind states also have control responsibilities because, among other things, the Act requires each state to adopt enforceable plans (*i.e.,* State Implementation Plans) to attain and maintain air quality standards. The requirements established for upwind states through this final rule will supplement downwind states' local emission control strategies. The downwind states' local control strategies, in conjunction with the emission reductions from upwind states that this rule will provide, promote attainment and maintenance of the 2008 ozone NAAQS.

The Clean Air Act's good neighbor provision requires states and the EPA to address interstate transport of air pollution that affects downwind states' ability to attain and maintain NAAQS. Other provisions of the CAA, namely sections 179B and 319(b), are available

[62] Fact Sheet. The EPA to reconsider Ozone Pollution Standards. *http://www.epa.gov/groundlevelozone/pdfs/O3_Reconsideration_FACT%20SHEET_091609.pdf.*

[63] *See* Letter from Cass R. Sunstein, Administrator, Office of Information and Regulatory Affairs, to Lisa Jackson, Administrator, U.S. Environmental Protection Agency (Sept. 2, 2011), available at *http://www.reginfo.gov/public/return/EPA_Return_Letter_9-2-2011.pdf.*

[64] *Id.*

[65] *EME Homer City I,* 696 F.3d at 31.

[66] *See, e.g.,* Memorandum from the Office of Air and Radiation former Assistant Administrator Gina McCarthy to the EPA Regions, "Next Steps for Pending Redesignation Requests and State Implementation Plan Actions Affected by the Recent Court Decision Vacating the 2011 Cross-State Air Pollution Rule," November 19, 2012; 78 FR 65559 (November 1, 2013) (final action on Florida infrastructure SIP submission for 2008 8-hour ozone NAAQS); 78 FR 14450 (March 6, 2013) (final action on Tennessee infrastructure SIP submissions for 2008 8-hour ozone NAAQS); Final Rule, Findings of Failure To Submit a Complete State Implementation Plan for section 110(a) Pertaining to the 2008 Ozone National Ambient Air Quality Standard, 78 FR 2884 (January 15, 2013).

[67] *EPA* v. *EME Homer City Generation, L.P.,* 133 S. Ct. 2857 (2013) (granting the EPA's and other parties' petitions for certiorari).

[68] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. at 1600–01.

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to deal with NAAQS exceedances not attributable to the interstate transport of pollution covered by the good neighbor provisions but caused by emission sources outside the control of a downwind state. These provisions address international transport and exceptional events, respectively.[69] [70]

Comment: Some commenters claimed that local measures should be evaluated first, before requiring upwind emission reductions, in terms of efforts to attain and maintain the 2008 ozone NAAQS. Commenters also claimed that the EPA failed to adequately evaluate local measures to reduce ozone concentrations at identified nonattainment and maintenance receptors.

Response: The EPA disagrees with these comments. First, the Clean Air Act makes no reference to considering local measures before upwind measures in planning for attainment and maintenance of a NAAQS. In fact, the EPA notes that commenters' local-first argument is at opposition with the NAAQS implementation schedule provided in the CAA. Specifically, the Clean Air Act requires upwind states to submit infrastructure SIPs, including requirements to address interstate transport, within three years of promulgation of a new or revised NAAQS. Submission of interstate transport SIP requirements is one of the first chronological actions in NAAQS implementation. States are required to submit attainment plans for Moderate ozone nonattainment areas within 3 years of nonattainment designation, which normally comes two to three years after promulgation of a new or revised NAAQS. Marginal ozone nonattainment areas that fail to meet their attainment deadlines and are reclassified as Moderate areas may be provided a new deadline upon reclassification to submit Moderate area plans. *See* CAA section 182(i). Depending on the designations schedule, Moderate area attainment plans would be due approximately 5 years after promulgation of a new or revised standards, *i.e.,* 2 years after interstate transport SIPs, and plans for reclassified areas would follow even later. Commenters' request that the EPA not evaluate upwind obligations until downwind controls have been evaluated is therefore unavailing under the statutory structure. If states or the EPA waited until Moderate area attainment plans were due before requiring upwind reductions, then these upwind reductions would be delayed several years beyond the mandatory CAA schedule. Further, the CAA implementation timeline implies that requiring local reductions first would place an inequitable burden on downwind areas by requiring them to plan for attainment and maintenance without any upwind actions. Adhering to the CAA schedule provides that downwind areas are able to plan for attainment and maintenance while accounting for previously determined and quantified upwind actions.

Further, the commenters are incorrect in asserting that the EPA has not considered any local controls obligations at downwind receptors when quantifying upwind state emission reductions. As described further in section VI, when evaluating air quality improvements at each level of control stringency, the EPA assumed that the downwind state home to an identified receptor would make emission reductions at an equivalent level of control stringency. While this final rule does not mandate any particular level of reductions in downwind states, the analysis to quantify upwind state reductions assumes that downwind states share responsibility for addressing identified air quality problems with the upwind states.

2. Focusing on 2017 for Analysis and Implementation

The EPA is aligning the analysis and implementation of this final rulemaking with the 2017 ozone season (May 1–September 30) in order to assist downwind states with timely attainment of the 2008 ozone NAAQS. On March 6, 2015, the EPA's final 2008 Ozone NAAQS SIP Requirements Rule [71] revised the attainment deadline for ozone nonattainment areas currently designated as Moderate to July 20, 2018. The EPA established this deadline in the 2015 Ozone SIP Requirements Rule after previously establishing a deadline of December 31, 2018, which was vacated by the D.C. Circuit Court in *Natural Resources Defense Council* v. *EPA.* [72] In order to demonstrate attainment by this deadline, states will need to rely on design values calculated using ozone season data from 2015 through 2017, since the July 20, 2018 deadline does not afford enough time for measured data of the full 2018 ozone season. Therefore, consistent with the court's instruction in *North Carolina,* the EPA has identified achievable upwind emissions reductions and aligned implementation of these reductions, to the extent possible, for the 2017 ozone season. These 2017 reductions can positively influence air quality that would be used to demonstrate attainment. To the extent that ozone improvements in 2017 yield the 4th highest daily maximum 8-hour average concentrations for all monitors in the area that are below the level of the 2008 ozone NAAQS, states can request a 1-year attainment date extension under CAA section 181(a)(5), as interpreted in 40 CFR 51.1107.

The EPA has therefore conducted its analyses of downwind air quality problems and upwind state contributions based on projections to the 2017 ozone season. The EPA also limits its assessment of NO_X mitigation potential to those strategies that are feasible for the 2017 ozone season. This rulemaking also finalizes the 2017 ozone season as the initial control period for the finalized FIPs.

Comment: Several comments claimed that requiring reductions beginning with the 2017 ozone season does not provide sufficient time to implement emission reductions for compliance with this rulemaking's limitations on emissions.

Response: The EPA disagrees with these comments. In establishing its limitations on emissions (*i.e.,* emission budgets and corresponding assurance levels), under the CSAPR Update rule the EPA explicitly took into account the fact that only certain emission reduction strategies can be implemented for the 2017 ozone season. Specifically, the

[69] The EPA recognizes that both in-state and upwind wildfires may contribute to monitored ozone concentrations. The EPA encourages all states to consider how the appropriate use of prescribed fire may benefit public safety and health by resulting in fewer ozone exceedances for both the affected state and their neighboring states.

[70] The CAA and the EPA's implementing regulations, specifically the Exceptional Events Rule at 40 CFR 50.14, allow for the exclusion of air quality monitoring data from regulatory determinations when events, including wildland fires, contribute to NAAQS exceedances or violations if they meet certain requirements, including the criterion that the event be not reasonably controllable or preventable. Wildland fires can be of two types: Wildfire (unplanned) and prescribed fire (planned). Under the Exceptional Events Rule, unless there is evidence to the contrary, wildfires are considered, by their nature, to be not reasonably controllable or preventable. Because prescribed fires on wildland are intentionally ignited for resource management purposes, to meet the not reasonably controllable or preventable criterion, they must be conducted under a certified Smoke Management Program or employ basic smoke management practices. Both types of wildland fire must also satisfy the other rule criteria for influenced air quality monitoring data to be excluded under the Exceptional Events Rule. In November 2015, the EPA proposed revisions to the Exceptional Events Rule and released a draft guidance document, which applies the proposed rule revisions to wildfire events that could influence ozone concentrations. These actions, which the EPA intends to finalize in the summer of 2016, further clarify the treatment of wildland fires under the Exceptional Events Rule.

[71] 80 FR 12264, 12268 (Mar. 6, 2015); 40 CFR 51.1103.

[72] 777 F.3d 456 (D.C. Cir. 2014).

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agency considered activities that may be implemented quickly, such as turning on and optimizing existing SCR at power plants. The emission budgets are thus calculated to reflect only those activities that can be implemented by the 2017 ozone season.[73] Further, the CSAPR Update rule provides regulated entities the ability to comply by means of the CSAPR limited interstate trading program, which gives flexibility in compliance and does not require any specific action for compliance at any specific facility, other than holding allowances to cover emitted tons of pollution. Within this allowance trading program, the EPA also facilitates compliance by carrying over some banked allowances that can be used for compliance with the CSAPR Update, starting in 2017. More information about compliance feasibility is provided in section VII. Additionally, the EPA provides an EGU NO_X Mitigation Strategies Final Rule TSD, which is found in the docket for this final rule that further discusses the feasibility of complying with this rule's emissions requirements.

3. The CSAPR Framework

The original CSAPR used a four-step framework to address the requirements of the good neighbor provision for the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS.[74] The EPA is following the same CSAPR framework in this CSAPR Update to identify and address the requirements of the good neighbor provision with respect to the newer 2008 ozone NAAQS. By applying the CSAPR framework with respect to the newer 2008 ozone NAAQS, the EPA is using an approach that is informed by public comment on the original CSAPR rulemaking and has been reviewed in litigation by the D.C. Circuit Court of Appeals and the Supreme Court. The four steps are: (1) Identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards [75] (*i.e.,* NAAQS); (2) determining which upwind states contribute to these identified problems in amounts sufficient to ''link'' them to the downwind air quality problems; (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to nonattainment or interfere with maintenance of a standard; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, reducing the identified upwind emissions through regional emission allowance trading programs. The following subsections include summaries of the four steps and comments and responses on the application of the CSAPR framework from the proposal.

a. *Step 1.* In the original CSAPR, downwind air quality problems were assessed using modeled future air quality concentrations for a year aligned with attainment deadlines for the NAAQS considered in that rulemaking. The assessment of future air quality conditions generally accounts for on- the-books emission reductions [76] and the most up-to-date forecast of future emissions in the absence of the transport policy being evaluated (*i.e.,* base case conditions). The locations of downwind air quality problems are identified as those with monitors that are projected to be unable to attain (*i.e.,* nonattainment receptor) or maintain (*i.e.,* maintenance receptor) the standard. This final rule follows this same general approach. However, in this rule, the EPA also considers current monitored air quality data to further inform the projected identification of downwind air quality problems for this final rule. The proposed CSAPR Update put forward this change from the original CSAPR approach and commenters generally supported consideration of monitoring data. Further details and application of step one are described in section V of this rulemaking.

Comment: Some commenters challenged the methodology proposed by the EPA to identify maintenance receptors in the step 1 analysis. Commenters contend that maintenance receptors for purposes of the CSAPR Update analysis should only be identified as those areas that were previously designated nonattainment. The commenters explain that the proposed methodology for identifying maintenance receptors is inconsistent with how the statute defines maintenance areas in section 175A of the CAA. Other commenters contend that the EPA should not identify an area as a maintenance receptor where the area currently measures clean data. The commenters are concerned that it is arbitrary and capricious to treat clean data differently with respect to identifying nonattainment receptors and maintenance receptors.

Response: The EPA does not agree with the commenters' contention that it may only identify maintenance receptors as those areas that were once designated nonattainment. Such an interpretation would be contrary to the statutory process for SIP development. Area designations occur two to three years after promulgation of a new or revised NAAQS pursuant to CAA section 107(d)(1)(B)(i). State SIP submissions pursuant to CAA section 110(a)(1) and (2), including good neighbor SIPs, are also due three years after promulgation of a new or revised NAAQS. Attainment plans for those areas designated nonattainment are due between 18 months and 4 years after designation, depending on the pollutant, pursuant to the requirements of subpart D of title I of the CAA. Re-designations, including application of the requirements of CAA section 175A to develop a maintenance plan, by definition, occur after the initial designation and frequently well after the development and submission of the state's attainment plan.

Given that the statutory timeframe for development of the good neighbor SIP requires submission before the downwind state's development of an attainment plan, before an area is likely to be re-designated from nonattainment to attainment (with the attendant maintenance plan obligations), and in some cases before or at the same time designations for a new or revised standard might be finalized, the EPA does not believe it is reasonable to interpret the good neighbor provision to make states' emission reduction obligations dependent on either current or prior designations of downwind areas with potential air quality problems in other states. While circumstances related to implementation of the 2008 ozone NAAQS (described in more detail earlier) led many states to delay submission of good neighbor SIPs addressing that standard and while the EPA is, in this case, addressing its FIP obligation many years after designations were finalized, these circumstantial factors do not revise the Congressional intent inherent in the statutory structure just described.

Moreover, section 110(a)(1) instructs states to submit plans that provide for the ''implementation, maintenance, and enforcement'' of the NAAQS. Nothing in the provision indicates that states need only address maintenance of air quality

[73] This is true with one exception. The EPA finds that for Arkansas it is reasonable to delay EGU NO_X reduction potential for certain new combustion controls until 2018 and therefore gives Arkansas a 2017 budget that does not reflect these controls and a 2018 budget that does reflect these controls. This issue is discussed further in Section VI.

[74] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

[75] As noted in section IV, the term maintenance used under the CSAPR framework is distinct from the term as applied the plan required of nonattainment areas redesignated to attainment.

[76] Since CSAPR was designed to replace CAIR, CAIR emissions reductions were not considered ''on-the-books.''

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in those areas that were once formally designated nonattainment as to a particular NAAQS. Therefore, where CAA section 110(a)(2)(D)(i)(I) instructs state plans to prohibit emissions activity within the state which will "interfere with maintenance" of the NAAQS in any other state, this provision is logically read consistent with section 110(a)(1) to require upwind states to address the maintenance of the NAAQS in all areas downwind. In this respect, the EPA does not agree with commenters that its identification of maintenance receptors for purposes of the good neighbor provision is constrained by the applicability of the provisions in CAA section 175A. Although the statute invokes the word "maintenance" in that provision to describe the requirements for maintenance plans that apply in areas that have been re-designated from nonattainment to attainment, the good neighbor provision neither implicitly nor explicitly indicates that a state's evaluation of whether it interferes with maintenance in another state should be limited to evaluation of areas subject to the requirements of section 175A.

Regardless of designation, any area may violate the NAAQS if emissions affecting air quality in that area are not adequately controlled. The court in *North Carolina* was specifically concerned with such areas when it rejected the view that "a state can never 'interfere with maintenance' unless the EPA determines that at one point it 'contribute[d] significantly to nonattainment.' " 531 F.3d at 910. The court pointed out that areas barely attaining the standard due in part to emissions from upwind sources would have "no recourse" pursuant to such an interpretation. *Id.* Accordingly, the court instructed the EPA to give "independent significance" to the maintenance prong of CAA section 110(a)(2)(D)(i)(I) by separately identifying such downwind areas for purposes of defining states' obligations pursuant to the good neighbor provision.

In areas that are currently measuring clean data with respect to the 2008 ozone NAAQS, these measurements can be driven by a number of factors, including recent meteorology that is not conducive to ozone formation. Due to the variable nature of meteorology, the fact that such areas are currently attaining the standard does not address whether the areas might struggle to maintain the standard in the future, which was precisely the issue raised in *North Carolina.* The EPA's approach to defining maintenance receptors directly responds to these concerns raised by the D.C. Circuit in *North Carolina.* Thus, although the EPA has considered recent monitored data for purposes of identifying nonattainment receptors in this rulemaking, it does not believe the data should inform the agency's identification of maintenance receptors.

b. *Step 2.* The original CSAPR used a screening threshold of one percent of the NAAQS [77] to identify upwind states that were "linked" to downwind air pollution problems. States were identified as needing further evaluation for actions to address transport if their air quality impact was greater than or equal to one percent of the NAAQS for at least one downwind problem receptor (*i.e.,* nonattainment or maintenance receptor identified in step 1). For ozone, the impacts include those from total emissions within the state of anthropogenic volatile organic compounds (VOC) and NO_X from all sectors. The EPA evaluated a given state's contribution based on the average relative downwind impact calculated over multiple days. States whose air quality impacts to all downwind problem receptors were below this threshold did not require further evaluation for actions to address transport—that is, these states were determined to make insignificant contributions to downwind air quality problems and therefore have no emission reduction obligations under the good neighbor provision. The EPA used this threshold because it determined that much of the ozone nonattainment problem in the eastern half of the United States results from collective impacts of relatively small contributions from a number of upwind states. Use of the one percent threshold for CSAPR is discussed in the preambles to the proposed and final CSAPR rules. *See* 75 FR 45237 (Aug. 2, 2010); 76 FR 48238 (Aug. 8, 2011).

The EPA is using the same approach for identifying states that are linked to downwind nonattainment and maintenance receptors in this final rule because the EPA's analysis shows that much of the ozone nonattainment problem being addressed by this rule is still the result of the collective impacts of relatively small contributions from many upwind states. Therefore, application of a uniform threshold helps the EPA to identify those upwind states that should share responsibility for addressing the downwind nonattainment and maintenance problem to which they collectively contribute. Continuing to use one percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emission transport under the "good neighbor" provision from one NAAQS to the next. Accordingly, the EPA has applied an air quality screening threshold calculated as one percent of the 2008 ozone NAAQS, 0.75 ppb, to identify those states "linked" to downwind nonattainment and maintenance receptors with respect to the 2008 ozone NAAQS which require further analysis to identify potential emission reductions. Consistent with the EPA's findings in the original CSAPR, the agency has determined that states with contributions to all downwind nonattainment and maintenance receptors below this threshold make insignificant contributions to downwind air quality problems and therefore have no emission reduction obligations under the good neighbor provision with respect to the 2008 ozone NAAQS. Application of step 2 is described in section V.

Comment: Some commenters supported the continued use of an air quality screening threshold of one percent of the NAAQS to identify upwind states requiring further analysis. However, some commenters opposed the use of the proposed one percent threshold because the commenters claim that the EPA had not technically demonstrated that continued use of the one percent screening metric is appropriate for linking an upwind state to a downwind nonattainment or maintenance receptor with respect to the 2008 ozone NAAQS. Some commenters believed that use of the one percent threshold was too stringent given that the proposed rule only focuses on emission reductions from one sector, EGUs. Other commenters believed that one percent (0.75 ppb) was not stringent enough, and they recommended using a lower value such as 0.5 ppb.

Response: The EPA continues to believe that it is appropriate to use a threshold of one percent of the NAAQS for identifying states which merit further analysis to determine if emission reductions may be warranted. The EPA has consistently determined in past analyses conducted for the NO_X SIP Call, CAIR, and CSAPR that ozone nonattainment problems generally result from relatively small contributions from many upwind states, along with contributions from in-state sources and in some cases, substantially larger

[77] *See* section IV.B for a discussion of the Supreme Court's consideration of the one percent threshold.

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contributions from a subset of particular upwind states.[78]

The EPA determined that it is appropriate to use a low air quality threshold when analyzing states' collective contributions to downwind nonattainment and maintenance for ozone as well as $PM_{2.5}$.

To further support the EPA's evaluation of the appropriate screening threshold to use for this purpose, the EPA compiled the contribution modeling results from the air quality modeling conducted for this rule in order to analyze the impact of different possible thresholds. The EPA notes that similar contribution modeling data were available for comment in the docket for the proposed CSAPR Update. This compiled analysis demonstrates the reasonableness of continuing to use one percent as an air quality threshold to account for the combined impact of relatively small contributions from many upwind states. *See* the Air Quality Modeling Technical Support Document for the Final Cross-State Air Pollution Rule Update (AQM TSD). For each of the ozone receptors identified in the final CSAPR Update rule analysis, the EPA identified: (1) The total upwind state contributions, and (2) the amount of the total upwind state contribution that is captured at one percent, five percent, and half (0.5) percent of the NAAQS. The EPA continues to find that the total collective contribution from upwind states' sources represent a significant portion of the ozone concentrations at downwind nonattainment and maintenance receptor locations. This analysis shows that the one percent threshold generally captures a substantial percentage of the total pollution transport affecting downwind states without also implicating states that contribute insignificant amounts.

In response to commenters who advocated for a lower threshold, the EPA observes that the analysis shows that a lower threshold would result in relatively modest increases in the overall percentage of ozone pollution transport captured relative to the amounts captured at the one percent level at a majority of the receptors. A lower percent threshold could lead to emission reduction responsibilities in additional states that individually have a relatively small impact on those receptors, compared to other upwind states — an indicator that emission controls in those states are likely to have a smaller air quality impact at the downwind receptor.

In response to commenters who advocated for a higher threshold, the EPA observes that the analysis of a 5 percent threshold shows that a higher threshold would result in a relatively large reduction in the overall percentage of ozone pollution transport captured relative to the amounts captured at the one percent level at a majority of the receptors. In fact, at a 5 percent threshold there would not be any upwind states linked to the nonattainment and maintenance receptors in Texas.

As a result of our analyses of higher and lower thresholds, as described in the AQM TSD, the agency is not convinced that selecting a threshold below one percent or above one percent is necessary or desirable.

Comment: Some commenters suggested more specifically that a 0.5 ppb threshold would be more appropriate for upwind states contributing to downwind receptors in Texas. The commenters note that the lower threshold will add more states in the rule and address more of the maximum combined upwind state impacts to Texas' receptors.

Response: The EPA agrees that a lower threshold of 0.5 ppb would capture more of the upwind states that contribute to Texas receptors. However, the contribution of upwind state interstate transport to receptors in Texas is less than the upwind state interstate transport contribution identified for other downwind nonattainment and maintenance receptors in this rule. Therefore, the potential ozone reductions that would result from including additional upwind states are relatively small. The EPA believes it is therefore reasonable to use a uniform threshold for all states included in this rule.

c. *Step 3.* For states that are linked in step 2 to downwind air quality problems, the original CSAPR evaluated emission reductions available in upwind states by application of uniform levels of control stringency, represented by cost. The EPA evaluated NO_X reductions that were available in upwind states by applying uniform levels of control stringency to entities in these states. For each uniform level of control stringency evaluated, the EPA used a multi-factor test to evaluate cost, NO_X reduction potential, and downwind air quality impacts. This multi-factor test was used to select a uniform level of control stringency on the remaining allowable emissions—those available after reducing significant contribution to nonattainment or interference with maintenance of a NAAQS downwind. The use of uniform control stringency also reasonably apportions upwind responsibility among linked upwind states. This approach was upheld by the Supreme Court in *EPA* v. *EME Homer City Generation*.[79]

In this final rule, the EPA applies this approach to establish EGU NO_X emission budgets that reflect NO_X reductions necessary to reduce interstate ozone transport for the 2008 NAAQS. In this process, the EPA also explicitly evaluates whether the budget quantified for each state would result in over-control, as required by the Supreme Court and the D.C. Circuit.[80] Specifically, the multi-factor test is used to evaluate whether an upwind state is linked solely to downwind air quality problems that are resolved at a given uniform control stringency, or if upwind states reduce their emissions at a given uniform control stringency such that contributions from sources in the state no longer meet or exceed the one percent air quality contribution threshold. This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of potential over-control, results in the EPA's quantification of upwind emissions that significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS downwind. The EPA's assessment of significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS and our development of EGU NO_X ozone season emission budgets is described in section VI of this document.

Comment: Some commenters claim that the CSAPR framework requires the same remedy for states linked solely to maintenance receptors as it does for states linked to nonattainment receptors and these commenters suggested that states linked solely to maintenance problems should have a different, less stringent requirement. These commenters contend that, as a result, the EPA has failed to given independent significance to the ''interfere with maintenance'' clause of CAA section 110(a)(2)(D)(i)(I) as compared to the ''significant contribution'' clause of that provision. The commenters contend that it constitutes over-control to impose budgets based on the same uniform control stringency to address both states that interfere with maintenance of the NAAQS in downwind states and those

[78] *See* NO_X SIP Call, 63 FR 57356,57375–377 (October 27, 1998); CAIR, 70 FR 25162, 25172 & 25186 (May 12, 2005); CSAPR, 76 FR 48208, 48236–237 (August 8, 2011).

[79] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. at 1606–07.

[80] *Id.* at 1608; *EME Homer City II,* 795 F.3d at 127.

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that significantly contribute to nonattainment in downwind states. The commenters cite the Supreme Court's opinion in *EPA* v. *EME Homer City Generation,* explaining that the EPA may only limit emissions ''by just enough to permit an already-attaining State to maintain satisfactory air quality.'' 134 S. Ct. at 1604 n.18.

Response: The EPA disagrees with these comments. The CSAPR framework gives independent meaning to the ''maintenance'' prong of CAA section 110(a)(2)(D)(i)(I) as required by D.C. Circuit's decision in *North Carolina.* By identifying those downwind areas that are at risk of exceeding the NAAQS if historical meteorology conducive to ozone formation occurs again, the EPA thereby defines upwind states linked to these areas as having a transport obligation.[81] In its decision, on remand from the Supreme Court, the D.C. Circuit confirmed that the EPA's approach to identifying maintenance receptors in CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136. The EPA's analysis indicates that the maintenance receptors identified in this rulemaking are at risk of NAAQS violations and therefore should be afforded protection.

CAA section 110(a)(2)(D)(i)(I) requires that state implementation plans, or the EPA where such plans are insufficient, prohibit emissions which will interfere with maintenance of the NAAQS in downwind states. Once the EPA identifies maintenance receptors, the EPA is compelled by the CAA to prohibit emissions that would jeopardize the ability of these receptors to maintain the standard. Put another way, it would be inconsistent with the CAA for the EPA to identify receptors that are at risk of NAAQS violations given certain conditions due to transported upwind emissions and then not prohibit the emissions that place the receptor at risk.

Moreover, the Supreme Court has acknowledged that the ''interfere with maintenance'' clause of the good neighbor provision is ambiguous with respect to how the EPA should quantify and allocate the emission reduction obligations for states linked to downwind maintenance concerns. The Supreme Court clearly stated that ''[n]othing in *either* clause of the Good Neighbor Provision provides the criteria by which EPA is meant to apportion responsibility.'' *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. at 1604 n.18 (emphasis in original). Thus, the EPA is afforded deference to develop an appropriate application of this requirement so long as it is a ''permissible construction of the statute.'' *Chevron, U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 843, 104 S. Ct. 2778, 2782 (1984). The Supreme Court held that it was a permissible interpretation of the statute to apportion responsibility for states linked to nonattainment receptors considering ''both the magnitude of upwind States' contributions and the cost associated with eliminating them.'' *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. at 1606. It is equally reasonable and permissible to use these factors to apportion responsibility among upwind states linked to maintenance receptors because the goal in both instances is to prohibit the ''amounts'' of pollution that will either significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind. The EPA's contribution analysis demonstrates that the amounts of pollution prohibited through implementation of the budgets finalized in this rule will, under certain projected conditions, otherwise contribute to downwind nonattainment and interfere with maintenance of the 2008 ozone NAAQS in downwind states.

All of that being said, contrary to the commenters' contention, the CSAPR framework does not necessarily dictate that upwind states linked solely to maintenance receptors be subject to the same level of NO_X control stringency as upwind states linked to nonattainment receptors. Rather, the selection of NO_X control stringency is in part informed by the difficulty of resolving the identified downwind air quality problem to which each state is linked. (*See* the components, including air quality considerations, of the multi-factor test described in section VI.D.)The data and analysis for the CSAPR Update show that the maintenance-only receptors generally represent less severe air quality problems than the nonattainment receptors. Specifically, in the final CSAPR Update modeling, maintenance-only receptors have an average maximum design value that is 1.9 ppb above the 2008 ozone NAAQS while nonattainment receptors have an average maximum design value that is 3.1 ppb above the NAAQS. As described in section VI.D, the specific emission reduction obligation for each state is limited by the amount of air quality improvement needed to either attain or maintain the NAAQS at the particular receptor to which the state's emissions are linked. These data therefore demonstrate that states linked to maintenance-only receptors would generally have a lesser emission reduction obligation than states linked to nonattainment receptors, but for the partial nature of this rule.

The original CSAPR rulemaking provides an example of this differentiation of control stringency based on the severity of downwind air quality problems. In that rulemaking, some states reduced their significant contribution of SO_2 for purposes of addressing downwind $PM_{2.5}$ nonattainment and maintenance problems at a lower uniform cost control stringency, while other states needed to comply with budgets calculated at a higher uniform control stringency in order to resolve their transport obligations.[82]

In the case of a full solution, which EPA is not promulgating in this action, a similar differentiation in the level of control stringency may emerge between the upwind states linked solely to maintenance and the upwind states linked to nonattainment. However, given the unique circumstances of this rulemaking and the need to obtain emission reductions on a tight timeframe in order to assist downwind states with meeting the downwind 2018 attainment deadline, the EPA is only quantifying a subset of each state's emission reduction obligation pursuant to the good neighbor provision. The EPA's analysis shows that even when all the emission reductions required by this rule are in place, both attainment and maintenance problems at downwind receptors may remain, and the EPA will need to evaluate whether the upwind states' emission reduction obligations should be more stringent considering other factors not addressed by this rule, including control strategies that can be implemented on a longer timeframe or by other source categories. Thus, the commenters are incorrect to state that the EPA is necessarily imposing the same remedy (in the form of the same level of control stringency) for states linked only to maintenance-only receptors as those linked to nonattainment receptors by way of applying the CSAPR framework. It is only due to the partial nature of the remedy provided by this rule that the EPA is finalizing a single uniform level of control stringency for all CSAPR Update states.

[81] 531 F.3d 896, 910–911 (D.C. Cir. 2008) (noting that the EPA's failure to separately address maintenance problems under CAIR ''unlawfully nullifies that aspect of the statute and provides no protection for downwind areas that, despite the EPA's predictions, still find themselves struggling to meet NAAQS due to upwind interference'').

[82] 76 FR at 48257–259.

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d. *Step 4.* Finally, the original CSAPR used allowance trading programs to implement the necessary emission reductions represented by the emission budgets identified in step 3. Emission allowances were issued to units covered by the trading program, and each covered unit can then retain and/or acquire however many allowances are needed to cover its ozone season NO_X emissions over the course of each control period; however, because the total number of allowances issued in each period is limited to the sum of the states' emission budgets, total emissions across all affected EGUs are similarly limited such that overall emissions are controlled. Additionally, the original CSAPR included variability limits, which define the amount by which collective emissions within a state may exceed the level of that state's budget in a given control period to account for variability in EGU operations while still ensuring that the necessary emission reductions are achieved in each state. The variability limits for the CSAPR NO_X ozone season trading program is 21 percent of each state's budget. CSAPR set assurance levels equal to the sum of each state's emission budget plus its variability limit. The original CSAPR included assurance provisions that would require additional allowance surrenders in the instance that emissions in the state exceed the state's assurance level. This limited interstate trading approach is responsive to previous court decisions.[83] *See* discussion in section VII of this preamble. The EPA is applying this same approach to implement reductions in interstate transport for the 2008 ozone NAAQS in the CSAPR Update. Implementation of the CSAPR Update allowance trading program (CSAPR NO_X ozone season Group 2) is described in section VII of this final rule. This new program is substantially similar to the existing CSAPR NO_X ozone season program.

Comment: Some stakeholders have observed that a subset of existing post-combustion EGU NO_X controls (*e.g.,* SCR) may not have operated in recent years because CAIR or CSAPR allowance prices were below the operating costs of the controls. These commenters suggest that, accordingly, CAIR or CSAPR did not achieve optimal environmental protection, as identified by requiring existing controls to operate.

Response: Regional allowance trading programs set a limit on the overall amount of allowable emissions. This limit reflects a reduction from uncontrolled emission levels and compliance is demonstrated through an allowance trading program that allows regulated entities the flexibility to determine their own compliance path. In states that participated in both CAIR and CSAPR ozone season programs, summer NO_X emissions dropped by 20 percent from 2009 to 2015, and compliance was demonstrated nearly 100 percent of the time due to rigorous emissions monitoring and allowance tracking. These outcomes, combined with air quality improvements, demonstrate the environmental achievements of these programs. The EPA notes that the allowance prices were low because of significant emission reductions that took place by other means (*e.g.,* new low-emitting generating capacity coming online that replaced older, higher emitting generation as well as EGU retirements). These other means significantly reduced emissions and helped the power sector meet the CAIR and CSAPR emission budgets without relying on the use of allowances. In light of these and other dramatic reductions in power sector pollution, the supply of CAIR and CSAPR allowances rose and their prices fell. In this case, certain utilities appear to have turned off their emission controls, relying instead on purchased allowances. The EPA notes, however, that in this case, the overall net effect of these activities has been a significant reduction in emissions. The EPA expects that certain aspects of this final rule will alleviate some of these concerns about allowance prices. In particular, this action establishes new emission budgets to address the more stringent 2008 ozone NAAQS that are calculated based on a uniform cost that is reflective of, among other things, operating existing controls. *See* section VI in this preamble on EGU NO_X reductions and emission budgets.

4. Partial Versus Full Resolution of Transport Obligation

Given the unique circumstances surrounding the implementation of the 2008 ozone standard that have delayed state and the EPA's efforts to address interstate transport, at this time the EPA is focusing its efforts on the immediately available and cost-effective emission reductions that are achievable by the 2017 ozone season.

This rulemaking establishes (or revises currently established) FIPs for 22 eastern states under the good neighbor provision of the CAA. These FIPs contain requirements for EGUs in these states to reduce ozone season NO_X emissions beginning with the 2017 ozone season. As noted in section VI, the EPA has identified important EGU emission reductions that are cost-effective and achievable by the 2017 ozone season in the covered states through actions such as turning on and operating existing pollution controls. These readily available emission reductions will assist downwind states in attaining and maintaining the 2008 ozone NAAQS and will provide human health and welfare benefits through reduced exposure to ground-level ozone pollution.

While these reductions are necessary to assist downwind states in attaining and maintaining the 2008 ozone NAAQS, and are necessary to address good neighbor obligations for these states, the EPA acknowledges that they may not be sufficient to fully address these states' good neighbor obligations.[84] With respect to the 2008 ozone standard, the EPA has generally not attempted to quantify the ozone season NO_X reductions that may be necessary to eliminate all significant contribution to nonattainment or interference with maintenance in other states. Given the time constraints for implementing NO_X reduction strategies, the EPA believes that implementation of a full remedy that includes emission reductions from EGUs as well as other sectors may not be achievable for 2017. However, a partial remedy is achievable for 2017 and therefore this rule focuses on these more immediately available reductions.

To evaluate full elimination of a state's significant contribution to nonattainment or interference with maintenance, non-EGU ozone season NO_X reductions and further EGU reductions that are achievable after 2017 should be considered. The EPA did not quantify non-EGU emissions reductions to address interstate ozone transport for the 2008 ozone NAAQS at this time because: (1) There is greater uncertainty in the non-EGU emission inventory estimates than for EGUs; and (2) based on current knowledge, there appear to be few non-EGU reductions that could be accomplished by the beginning of the 2017 ozone season. This is discussed further in section VI. Commenters generally agreed with the EPA that non-EGU emission reductions are not readily available for the 2017 ozone season but advocated that such reductions should

[83] *North Carolina,* 531 F.3d at 907–08 (EPA ''must include some assurance that it achieves something measurable towards the goal of prohibiting sources 'within the State' from contributing to nonattainment or interfering with maintenance in 'any other State'.'').

[84] The requirements for one state, Tennessee, will fully eliminate that state's significant contribution to downwind air quality problems.

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be included as appropriate in future mitigation actions.

Because the reductions in this action are EGU-only and because the EPA has focused the policy analysis for this action on reductions available by the beginning of the 2017 ozone season, CSAPR update reductions will represent, for most states, a first, partial step to addressing a given upwind state's significant contribution to downwind air quality impacts for the 2008 ozone NAAQS. Generally, a final determination of whether the EGU NO_X reductions quantified in this rule represent a full or partial elimination of a state's good neighbor obligation for the 2008 NAAQS is subject to an evaluation of the contribution to interstate transport from non-EGUs and further EGU reductions that are achievable after 2017. However, the EPA believes that it is beneficial to implement, without further delay, EGU NO_X reductions that are achievable in the near term. The NO_X emission reductions in this final rule are needed (although they may not be all that is needed) for these states to eliminate their significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS.

Comment: Several commenters questioned whether the CAA authorizes the EPA to implement a ''partial'' remedy, and also suggested that the partial nature of the proposed rule might ''circumvent'' prior courts' instructions regarding over-control. Those commenters note that the statute does not describe a process for issuing a partial FIP, and suggest that the EPA may only issue a FIP that fully eliminates transported contribution from upwind States. These commenters also imply that the Supreme Court's approval of the EPA's use of costs in defining ''significant contribution'' in *EME Homer City* does not apply to the agency's approach in this rule because the commenters claim that ''CSAPR was a transport rule that developed comprehensive state budgets [and][t]his proposed rule only addresses EGUs.''

Other commenters were concerned that the EPA is not meeting its statutory obligation to develop federal implementation plans that fully resolve downwind transport problems. These commenters argue that the EPA's own delay in preparing a rule to resolve interstate transport with respect to the 2008 ozone NAAQS caused the tight timeline now faced by the agency, and cannot be used as an excuse for failing to promulgate a full remedy by 2017. In the alternative, commenters argue that even if time constraints only allow the EPA to impose a partial remedy by the 2017 ozone season, the agency must provide a plan now for how it will achieve the rest of the necessary reductions in the future, and suggests the agency could do so by implementing a second implementation phase to go into effect after the 2017 ozone season.

Response: The EPA disagrees with commenters who suggest that the agency lacks authority to promulgate a partial FIP. As described in section III, the EPA's current statutory deadlines to promulgate FIPs extend until 2017 and 2018 for most states, and the EPA will remain mindful of those deadlines as it evaluates what further steps may be necessary to fully address interstate transport for the 2008 ozone NAAQS.

Nothing in section 110(c)(1) of the CAA suggests that the agency is barred from taking a partial step at this time (before its FIP deadline has passed), nor does the statutory text indicate Congress' intent to preclude the EPA from tackling this problem in a step-wise process. The D.C. Circuit has held on numerous occasions that agencies have the authority to tackle problems in an incremental fashion, particularly where a lack of resources or technical expertise make it difficult to immediately achieve the statute's full mandate. *See, e.g., Grand Canyon Air Tour Coal.* v. *FAA,* 154 F.3d 455, 478 (D.C. Cir. 1998); *City of Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (D.C. Cir. 1989) ('''[A]gencies have great discretion to treat a problem partially . . .' [and a] court will not strike down agency action 'if it were a first step toward a complete solution.'''); *Gen'l Am. Transp. Corp.* v. *ICC,* 872 F.2d 1048, 1059 (D.C. Cir. 1989); *Nat'l Ass'n of Broadcasters* v. *FCC,* 740 F.2d 1190, 1209–14 (D.C. Cir. 1984).

As explained previously, the EPA expects that a full resolution of upwind transport obligations would require emission reductions from sectors besides EGUs, including non-EGUs, and further EGU reductions that are achievable after 2017. Given the approaching July 2018 attainment deadline for the 2008 ozone NAAQS, developing a rule that would have covered additional sectors and emission reductions on longer compliance schedules would have required more of the EPA's resources over a longer rulemaking schedule to fully address. As discussed earlier in this document, the EPA is still in the process of developing information regarding available emission reductions from non-EGUs. Had the EPA waited to promulgate FIPs until that information was fully developed, we could not have assured emission reductions by 2017, in time to assist downwind states to meet the July 2018 attainment deadline. Accordingly, the EPA reasonably concluded that it was most prudent to promulgate a first step to address interstate transport for the 2008 ozone NAAQS that achieves those immediate reductions while addressing any remaining obligation that might be achievable on a longer timeframe in a separate rulemaking. The EPA intends to continue to collect information and undertake analyses for potential future emission reductions at non-EGUs that may be necessary to fully quantify states' interstate transport obligations in a future action.

The EPA further disagrees with commenters that its partial step here runs afoul of the Supreme Court and D.C. Circuit's instructions to avoid unnecessary over-control of upwind state emissions. As acknowledged by these commenters, due to its limited nature, this final action does not generally fully resolve downwind air quality problems, much less result in over-control of upwind state emissions relative to those air quality problems. *See* section VI for further discussion of the EPA's over-control analysis applied to address these courts' concerns. To the extent the EPA determines that it must require additional emission reductions in a later rulemaking to address interstate transport with respect to the 2008 ozone NAAQS, the EPA will also confirm that such reductions do not result in unnecessary over-control, consistent with the courts' instructions.

The EPA also disagrees that the Supreme Court's affirmation of its use of uniform control stringency to define significant contribution does not apply equally to this action. The commenters are mistaken insofar as they suggest that the original CSAPR regulated sources other than EGUs. This rule is identical to the original CSAPR rule in terms of the form of its remedy—an emission budget issued to each state, with allowances allocated to EGUs within the state. As in the original CSAPR, each state is free to submit a SIP to replace the FIP indicating that it will meet its emission budget via reductions from other sectors.

Furthermore, the EPA took a similar partial approach in quantifying interstate transport obligations with respect to the 1997 ozone NAAQS in the original CSAPR rulemaking. In that rule, the EPA's modeling indicated that there would be persistent nonattainment and maintenance problems at some receptors even after imposition of CSAPR's emission reductions. The EPA stated that, because additional emission reductions may be available at higher cost thresholds and from other sectors, such as non-EGUs, the emission

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reductions quantified in the rule did not necessarily fully quantify certain states' interstate transport obligation with respect to the 1997 ozone NAAQS.[85] Therefore, for states linked to those receptors, the agency concluded that its FIP provided a partial remedy, and that more emission reductions might be required in order to fully satisfy the states' transport obligations. As discussed later, this action now concludes that the EPA has fulfilled its FIP obligation with respect to the 1997 ozone NAAQS.

Finally, the EPA disagrees with commenters who suggest that the agency's ''own delay'' in implementing a transport rule to address the 2008 ozone NAAQS led to the current circumstances the states and the EPA now face. Until mid-2014 when the Supreme Court reversed the D.C. Circuit's original vacatur of CSAPR, the governing judicial holding was that the EPA lacked legal authority to promulgate any FIP addressing 2008 ozone transport obligations until the agency first quantified each state's emission reduction obligation, allowed states time to submit SIPs, and acted on those SIPs.[86] In July 2015, the D.C. Circuit issued its final decision generally upholding CSAPR, albeit subject to remand without vacatur of certain state budgets for reconsideration. The agency then proceeded on an expedited basis to issue a proposal to address its FIP obligation with respect to the 2008 ozone NAAQS in the fall of 2015. While commenters and the EPA may agree that it would be best if a full remedy could be possible by the 2017 ozone season such that downwind areas would receive those benefits in time for their Moderate area attainment deadlines, such a remedy simply is not feasible in the existing timeframe.

As noted previously, CAA section 110(c)(1) directs the EPA to promulgate a FIP ''at any time within two years'' of its disapproval or finding of failure to submit. For the majority of states affected, that timeframe will not end until 2017 or later, and as mentioned previously, *North Carolina* compels the EPA to identify upwind reductions and implementation programs to achieve these reductions by the 2017 ozone season. As the EPA has explained, it believes that reductions from other sectors besides EGUs should be evaluated in developing a full remedy, and the agency does not have sufficient information at this time to promulgate such a rule. Therefore, given these circumstances, the agency maintains that only requiring at this time necessary and achievable reductions by the 2017 ozone season is reasonable.

5. Why Focus on Eastern States

The final CSAPR Update focuses on collective contributions of ozone pollution from states in the east. In this action, the EPA is not addressing interstate emission transport in this action for the 11 western contiguous United States.[87] The CSAPR framework builds on previous eastern-focused efforts to address collective contributions to interstate transport, including the NO_X Budget Trading Program, CAIR, and the original CSAPR rulemaking. However, for western states, the EPA believes that there may be geographically specific factors to consider in evaluating interstate ozone pollution transport. Accordingly, given the need for near-term 2017 analysis and implementation of the CSAPR Update FIPs, the EPA focused this rulemaking on eastern states where the CSAPR method for assessing collective contribution has proven effective.

The EPA did not propose CSAPR Update FIPs to address interstate emission transport for western states and it is not finalizing FIPs for any of these states. However, the EPA notes that western states are not relieved of their statutory obligation to address interstate transport under the section 110(a)(2)(D)(i)(I). The EPA and western states, working together, are continuing to evaluate interstate transport obligations on a case-by-case basis. The EPA will fulfill its backstop role with respect to issuing FIPs for western states if and when that becomes necessary. The EPA notes that a 2-year FIP clock has started for New Mexico and California following the July 13, 2015 finding of failure to submit. The EPA notes that analyses developed to support this rule, including air quality modeling and the EPA's assessment of EGU NO_X mitigation potential, contain data that can be useful for western states in developing SIPs. The data from these analyses are available in the docket for this rulemaking.[88]

The proposed CSAPR Update solicited comment on whether to promulgate FIPs to address interstate ozone transport for the 2008 ozone NAAQS for western states, either in this rulemaking or in a subsequent rulemaking. Most commenters generally agreed with the EPA's proposal to exclude western states in this rule given that there may be geographically specific factors to consider in evaluating western states' interstate transport requirements.

6. Short-Term NO_X Emissions

In eastern states, the highest measured ozone days tend to occur within the hottest days or weeks of the summer. There tends to be a higher demand for electricity (for instance, to power air conditioners) on hotter days and with this increased power demand, ozone formation can increase causing peak ozone days. In discussions with representatives and officials of eastern states in April 2013 and April 2015, and in several letters to the EPA, officials from states that are part of the Ozone Transport Region (OTR) [89] states suggested that EGU emissions transported from upwind states may disproportionally affect downwind ozone concentrations on peak ozone days in the eastern U.S. These representatives asked that the EPA consider additional peak day limits on EGU NO_X emissions.

Comment: The proposed CSAPR Update took comment on whether or not short-term (*e.g.,* peak-day) EGU NO_X emissions disproportionately impact downwind ozone concentrations and, if they do, what EGU emission limits would be reasonable complements to the seasonal CSAPR requirement. Most commenters requested that the EPA not impose a short-term limit at this time.

Response: As noted previously,[90] the EPA finds that NO_X ozone season trading programs are effective at reducing peak ozone concentrations, and the agency is therefore continuing with a seasonal approach in this final rule. The EPA will continue to look at this matter with an eye towards future rulemakings.

C. Responding to the Remand of CSAPR NO_X Ozone Season Emission Budgets

As noted previously, in *EME Homer City II,* the D.C. Circuit declared invalid the CSAPR phase 2 NO_X ozone season emission budgets of 11 states, holding that those budgets over-control with respect to the downwind air quality problems to which those states were linked for the 1997 ozone NAAQS. 795 F.3d at 129–30, 138. As to ten of these

[85] 76 FR 48208, 48256–57 (August 8, 2011).

[86] *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7, 31 (D.C. Cir. 2012).

[87] For purposes of this action, the western U.S. (or the West) consists of the 11 western contiguous states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

[88] The OTR was established by the CAA amendments of 1990 to facilitate addressing the ozone problem on a regional basis and consists of the following states, or portions thereof: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, the District of Columbia and northern Virginia. 42 U.S.C. 7511c, CAA section 184.

[90] *See* Section IV.A.1.

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states, the court held that the EPA's 2014 modeling conducted to support the RIA for CSAPR demonstrated that air quality problems at the downwind locations to which those states were linked would resolve by phase 2 of the CSAPR program without further transport regulation (either CAIR or CSAPR). *Id.* at 129–30. With respect to Texas, the court held that the record reflected that the ozone air quality problems to which the state was linked could be resolved at a lower cost threshold. *Id.* The court therefore remanded those budgets to the EPA for reconsideration consistent with the court's opinion. *Id.* at 138. The court instructed the EPA to act "promptly" in addressing these issues on remand. *Id.* at 132.

The court's decision explicitly applies to 11 state budgets involved in that litigation: Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, and West Virginia. *Id.* at 129–30, 138. The EPA is finalizing FIPs for eight of those states to address interstate transport with respect to the 2008 ozone NAAQS: Maryland, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia, and West Virginia. The FIPs incorporate revised emission budgets that replace the budgets promulgated in the CSAPR rule to address the 1997 ozone NAAQS, the same budgets remanded by the D.C. Circuit for reconsideration. Further, in this rule, these budgets will be effective for the 2017 ozone season, the same period in which the phase 2 budgets that were invalidated by the court are currently scheduled to become effective. Therefore, this action provides an appropriate and timely response to the court's remand by replacing the phase 2 budgets promulgated in the CSAPR to address the 1997 ozone NAAQS, which were declared invalid by the D.C. Circuit, with budgets developed to address the revised and more stringent 2008 ozone NAAQS.[91]

For the three remaining original CSAPR ozone season states affected by this portion of the *EME Homer City II* decision, Florida, North Carolina, and South Carolina, the EPA is not finalizing FIPs because the EPA's analysis performed to support the final rule does not indicate that these states are linked to any identified downwind nonattainment or maintenance receptors with respect to the 2008 ozone standard. Because the 2008 ozone NAAQS is more stringent than the 1997 ozone NAAQS, this modeling necessarily indicates that Florida, North Carolina, and South Carolina are also not linked to any remaining air quality concerns with respect to the 1997 ozone standard for which the states were regulated in the original CSAPR. Accordingly, in order to address the Court's remand with respect to these three states' interstate transport responsibility under the 1997 ozone standard, the EPA is removing these states from the CSAPR ozone season trading program beginning in 2017 when the phase 2 ozone season emission budgets were scheduled to be implemented.[92]

Comment: Some commenters contend that the D.C. Circuit's remand of the phase 2 ozone season emission budgets in *EME Homer City II* requires the EPA to calculate new budgets to address the states' transport obligations with respect to the 1997 ozone NAAQS. These commenters contend that the EPA has not fully responded to the court's remand until it quantifies new budgets.

Response: As described earlier, the D.C. Circuit remanded 10 of CSAPR's ozone season NO_X budgets because the EPA's 2014 modeling conducted to support the RIA for CSAPR demonstrated that air quality problems at the downwind locations to which those states were linked would resolve by phase 2 of the CSAPR program without further transport regulation. The court essentially found that, by phase 2 of the CSAPR program, the CSAPR record did not support the EPA's authority to require emission reductions from these 10 states in order to address the 1997 ozone NAAQS. Thus, absent any new analysis demonstrating that these states are linked to downwind air quality problems with respect to the 1997 ozone NAAQS, the EPA does not have the authority to subject these states to the CSAPR NO_X ozone season emissions program beginning in 2017 and therefore does not have the authority to calculate new emission budgets for these states to address that standard. For Florida, North Carolina, and South Carolina, the EPA is therefore relieving sources in the states from the obligation to comply with the NO_X ozone season trading program in response to the remand. For the remaining seven states, sources located in these states will no longer be subject to the phase 2 NO_X ozone season budgets calculated to address the 1997 standard; however, because these states are linked to downwind air quality problems with respect to the 2008 ozone NAAQS, the EPA is promulgating new ozone season NO_X emission budgets at 40 CFR 97.810(a). *See* also 40 CFR 52.38(b)(2)(ii) (relieving sources in all ten of these states of the obligation to comply with the remanded phase 2 NO_X ozone season emission budgets after 2016).

With respect to Texas, because the court determined that the phase 2 ozone season budget was more stringent than necessary to address Texas' interstate transport obligation with respect to the 1997 ozone NAAQS, the EPA removed Texas's budget as a constraint in the 2017 air quality modeling. Even in the absence of this constraint, the updated 2017 air quality modeling shows that the predicted average DVs and maximum DVs are below the level of the 1997 ozone NAAQS for the downwind receptors of concern to which Texas was linked in the original CSAPR rulemaking with respect the 1997 ozone NAAQS. Accordingly, the EPA has concluded that it need not require additional emission reductions from sources in Texas in order to address the state's interstate transport obligation. Thus, sources in Texas will no longer be subject to the phase 2 NO_X ozone season budget calculated to address the 1997 standard; however, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, the EPA is promulgating a new ozone season NO_X emission budget to address that standard at 40 CFR 97.810(a). *See* also 40 CFR 52.38(b)(2)(ii) (relieving sources in Texas of the obligation to comply with the remanded phase 2 NO_X ozone season emission budgets after 2016).

Separately, various petitioners filed legal challenges in the D.C. Circuit to an EPA supplemental rule that added five

[91] The methodology for developing the budgets to address the 2008 ozone NAAQS is described in more detail in Sections VI and VII in this preamble. Section VI also includes an evaluation, as instructed by the court in *EME Homer City II,* to affirm that the budgets do not over-control with respect to downwind air quality problems identified in this rule. 795 F.3d at 127–28.

[92] One other state from the original CSAPR rulemaking, Georgia, was also not linked to any identified downwind nonattainment or maintenance receptors with respect to the 2008 ozone standard. However, when EPA promulgated the original CSAPR rulemaking, Georgia remained linked to an ongoing air quality problem with respect to the 1997 standard even after implementation of the emissions budget quantified in that rulemaking. Therefore, unlike Florida, North Carolina, and South Carolina, Georgia's budget was not subject to the same record issues identified by the D.C. Circuit related to the EPA's 2014 modeling and was not subject to remand for reconsideration. As Georgia remained linked to a continued air quality problem with respect to the 1997 ozone NAAQS in the original CSAPR analysis, the EPA retained this budget as a constraint in its analysis for this rule. Assuming compliance with that budget, the EPA determined that Georgia does not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS downwind. The EPA has also concluded, as discussed in section IV.D, that compliance with that budget is sufficient to fully address Georgia's interstate transport obligation with respect to the 1997 NAAQS.

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states to the CSAPR ozone season trading program, 76 FR 80760 (Dec. 27, 2011). *See Public Service Company of Oklahoma* v. *EPA,* No. 12–1023 (D.C. Cir., filed Jan. 13, 2012). The case was held in abeyance during the pendency of the litigation in *EME Homer City*. The case remains pending in the D.C. Circuit as of the date of signature of this rule.[93] The EPA notes that this rulemaking also promulgates FIPs for all five states added to CSAPR in the supplemental rule: Iowa, Michigan, Missouri, Oklahoma, and Wisconsin. These FIPs incorporate revised emission budgets that replace the budgets promulgated in the supplemental CSAPR rule to address the 1997 ozone NAAQS for these five states and will be effective for the 2017 ozone season. In light of the court's decision in *EME Homer City II,* the EPA examined the record supporting the CSAPR rulemaking and determined that, like the 10 states discussed earlier, the EPA's 2014 modeling conducted to support the RIA for CSAPR demonstrated that air quality problems at the downwind locations to which four of the states added to CSAPR in the supplemental rule, Iowa, Michigan, Oklahoma, and Wisconsin, were linked would resolve by phase 2 of the CSAPR program without further transport regulation (either CAIR or CSAPR). Accordingly, sources in these states will no longer be subject to the phase 2 NO_X ozone season budgets calculated to address the 1997 standard; however, because these states are linked to downwind air quality problems with respect to the 2008 ozone NAAQS, the EPA is promulgating new ozone season NO_X emission budgets at 40 CFR 97.810(a). *See* also 40 CFR 52.38(b)(2)(ii) (relieving sources in these four states of the obligation to comply with the original phase 2 NO_X ozone season emission budgets after 2016).

The D.C. Circuit also remanded without vacatur the CSAPR phase 2 SO_2 annual emission budgets for four states (Alabama, Georgia, South Carolina, and Texas) for reconsideration. 795 F.3d at 129, 138. This final rule does not address the remand of these CSAPR phase 2 SO_2 annual emission budgets. On June 27, 2016, the EPA released a memorandum outlining the agency's approach for responding to the D.C. Circuit's July 2015 remand of the CSAPR phase 2 SO_2 annual emission budgets for Alabama, Georgia, South Carolina, and Texas. The memorandum can be found at *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf*.

D. Addressing Outstanding Transport Obligations for the 1997 Ozone NAAQS

In the original CSAPR, the EPA noted that the reductions for 11 states may not be sufficient to fully eliminate all significant contribution to nonattainment or interference with maintenance for certain downwind areas with respect to the 1997 ozone NAAQS.[94] The 11 states are: Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, Tennessee, and Texas. In the original CSAPR, the EPA did not require EGU NO_X reductions represented by costs that exceeded $500 per ton because it noted that, at cost thresholds higher than $500 per ton, non-EGU reductions should also be considered. Additionally, the EPA's analysis projected continued nonattainment and maintenance problems at downwind receptors to which these upwind states were linked after implementation of the CSAPR trading programs. Specifically, persistent ozone problems were expected in Baton Rouge, Louisiana; Houston, Texas; and Allegan, Michigan according to the remedy case modeling conducted for the final rule. At that time the EPA did not quantify further ozone season EGU or non-EGU NO_X reductions that would be needed in these states to fully resolve the good neighbor obligation under the CAA with respect to the 1997 ozone NAAQS.

To evaluate whether additional emission reductions would be needed in these 11 states to address the states' full good neighbor obligation for the 1997 ozone NAAQS, the EPA reviewed the 2017 air quality modeling conducted for this rule, which includes emission reductions associated with the CSAPR phase 2 ozone season budgets that were not remanded. The modeling included the phase 2 ozone season budgets for 10 of the states listed above—all but Texas. For each of these states, the updated 2017 air quality modeling shows that the predicted average DVs and maximum DVs for 2017 are below the level of the 1997 ozone NAAQS for the downwind receptors of concern to which the 11 states were linked in the original CSAPR rulemaking with respect the 1997 ozone NAAQS, meaning that these receptors no longer qualify as either nonattainment or maintenance receptors for that NAAQS. The 2017 air quality modeling also shows that there are no other nonattainment or maintenance receptors to which these states would be linked with respect to the 1997 ozone NAAQS. Thus, the EPA finds that, with implementation of the original CSAPR NO_X ozone season emission budgets in the states not subject to the remand, emissions within these ten states no longer significantly contribute to downwind nonattainment or interference with maintenance for the 1997 ozone NAAQS. Thus, the promulgation of the CSAPR NO_X ozone season budgets in those states satisfied the EPA's FIP obligation pertaining to the good neighbor provision for the 1997 ozone NAAQS. The EPA further finds that, with implementation of the CSAPR Update NO_X ozone season emission budgets, emissions from these ten states also no longer significantly contribute to downwind nonattainment or interference with maintenance for the 1997 ozone NAAQS.

Despite the EPA's conclusion in CSAPR that the 1997 ozone transport problems to which Texas was linked were not fully resolved, the court concluded in *EME Homer City II* that the ozone season emission budget finalized for Texas resulted in over-control as to the ozone air quality problems to which the state was linked. 795 F.3d at 129–30. As described earlier, in response to this determination, the EPA removed Texas's phase 2 ozone season budget as a constraint in the 2017 air quality modeling. Even in the absence of this constraint, the updated 2017 air quality modeling shows that the predicted average DVs and maximum DVs are below the level of the 1997 ozone NAAQS for the downwind receptors of concern to which Texas was linked in the original CSAPR rulemaking with respect the 1997 ozone NAAQS. Accordingly, the EPA has concluded that it need not require additional emission reductions from sources in Texas in order to address the states' interstate transport obligation with respect to the 1997 standard, and that the EPA has therefore fully addressed its FIP obligation with respect to Texas. Texas remains subject to the CSAPR Update in this final rulemaking with respect to the 2008 ozone NAAQS.

No Texas emissions were linked to expected ozone problems in Baton Rouge, Louisiana, and Allegan, Michigan. As noted previously receptors for these areas are no longer a concern for the 1997 ozone NAAQS. The EPA finds that Texas emissions no longer contribute significantly to

[93] In 2012, the EPA also finalized two rules making certain revisions to CSAPR. 77 FR 10324 (Feb. 21, 2012); 77 FR 34830 (June 12, 2012). Various petitioners filed legal challenges to these rules in the D.C. Circuit, and the cases were also held in abeyance pending the litigation in *EME Homer City*. *See Wisconsin Public Service Corp.* v. *EPA,* No. 12–1163 (D.C. Cir., filed Apr. 6, 2012); *Utility Air Regulatory Group* v. *EPA,* No. 12–1346 (D.C. Cir., filed Aug. 9, 2012). The cases currently remain pending in the D.C. Circuit.

[94] *See* CSAPR Final Rule, 76 FR at 48220, and the CSAPR Supplemental Rule, 76 FR at 80760, December 27, 2011.

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nonattainment in, or interfere with maintenance by, any other state with respect to the 1997 ozone NAAQS. Thus, the EPA no longer has a FIP obligation pertaining to Texas emissions and the good neighbor provision for the 1997 ozone NAAQS.

V. Analyzing Downwind Air Quality and Upwind State Contributions

In this section, the agency describes the air quality modeling performed consistent with steps 1 and 2 of the CSAPR framework described earlier in order to (1) identify locations where it expects nonattainment or maintenance problems with respect to the 2008 ozone NAAQS for the 2017 analytic year chosen for this final rule, and (2) quantify the contributions from anthropogenic emissions from upwind states to downwind ozone concentrations at monitoring sites projected to be in nonattainment or have maintenance problems for the 2008 ozone NAAQS in 2017.

This section includes information on the air quality modeling platform used in support of the final rule with a focus on the base year and future base case emission inventories. The EPA also provides the projection of 2017 ozone concentrations and the interstate contributions for 8-hour ozone. The Final Rule AQM TSD in the docket for this rule contains more detailed information on the air quality modeling aspects of this rulemaking.

The EPA provided two separate opportunities to comment on the air quality modeling platform and air quality modeling results that were used for the proposed CSAPR Update. On August 4, 2015, the EPA published a Notice of Data Availability (80 FR 46271) requesting comment on these data. Specifically, in the NODA, the EPA requested comment on the data and methodologies related to the 2011 and 2017 emissions and the air quality modeling to project 2017 concentrations and contributions. In addition to the comments received via the NODA, the EPA also received comments on emissions inventories and air quality modeling in response to the proposed CSAPR Update. Comments on both the NODA and proposed rule were considered for this final rule.

A. Overview of Air Quality Modeling Platform

For the proposed rule, the EPA performed air quality modeling for three emissions scenarios: A 2011 base year, a 2017 baseline, and a 2017 control case that reflects the emission reductions expected from the rule.[95]

The EPA selected 2011 as the base year to reflect the most recent National Emissions Inventory (NEI). In addition, the meteorological conditions during the summer of 2011 were generally conducive for ozone formation across much of the U.S., particularly the eastern U.S. As described in the AQM TSD, the EPA's guidance for ozone attainment demonstration modeling, hereafter referred to as the modeling guidance, recommends modeling a time period with meteorology conducive to ozone formation for purposes of projecting future year design values [96]. The EPA therefore believes that meteorological conditions and emissions during the summer of 2011 provide an appropriate basis for projecting 2017 ozone concentrations in contributions.

As noted in section IV, the EPA selected 2017 as the projected analysis year to coincide with the attainment deadline for Moderate areas under the 2008 ozone NAAQS. The agency used the 2017 baseline emissions in its air quality modeling to identify future nonattainment and maintenance locations and to quantify the contributions of emissions from upwind states to 8-hour ozone concentrations at downwind locations. The air quality modeling of the 2017 baseline and 2017 illustrative control case emissions are used to inform the agency's assessment of the air quality impacts resulting from this rule.

For the final rule modeling, the EPA used the Comprehensive Air Quality Model with Extensions (CAMx) version 6.20 [97] to simulate pollutant concentrations for the 2011 base year and the 2017 future year scenarios. This version of CAMx was the most recent, publicly available version of this model at the time that the EPA performed air quality modeling for this rule. CAMx is a grid cell-based, multi-pollutant photochemical model that simulates the formation and fate of ozone and fine particles in the atmosphere. The CAMx model applications were performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 United States, the District of Columbia, and adjacent portions of Canada and Mexico using a horizontal resolution of 12 x 12 km. A map of the air quality modeling domain is provided in the AQM TSD.

The 2011-based air quality modeling platform includes 2011 base year emissions, 2017 future year projections of these emissions, and 2011 meteorology for air quality modeling with CAMx. In the remainder of this section, the EPA provides an overview of (1) the 2011 and 2017 emissions inventories, (2) the methods for identifying nonattainment and maintenance receptors along with a list of 2017 baseline nonattainment and maintenance receptors in the eastern U.S., (3) the approach to developing metrics to measure interstate contributions to 8-hour ozone, and (4) the predicted interstate contributions of upwind states to downwind nonattainment and maintenance in the eastern U.S. The EPA also identifies which predicted interstate contributions are at or above the screening threshold described in section IV, which the agency applies in step 2 of the CSAPR framework for purposes of identifying those upwind states that are linked to downwind air quality problems and which merit further analysis with respect to regulation of interstate transport of ozone for purposes of the 2008 ozone standard.

The EPA conducted an operational model performance evaluation of the 2011 modeling platform by comparing the 8-hour daily maximum ozone concentrations predicted during the May through September ''ozone season'' to the corresponding measured concentrations. This evaluation generally followed the approach described in the modeling guidance. Details of the model performance evaluation are described in the AQM TSD. The model performance results indicate that the 8-hour daily maximum ozone concentrations predicted by the 2011 CAMx modeling platform reflect the corresponding 8-hour observed ozone concentrations in the 12-km U.S. modeling domain. As recommended in the modeling guidance, the acceptability of model performance was judged by considering the 2011 CAMx performance results in light of the range of performance found in recent regional ozone model applications. These other modeling studies represent a wide range of modeling analyses that cover various models, model configurations, domains, years and/or episodes, and chemical mechanisms. Overall, the ozone model

[95] The 2017 control case is relevant to the EPA's policy analysis discussed in section VI and to the benefits and costs assessment discussed in section VIII of this preamble. It is not used to identify nonattainment or maintenance receptors or quantify the contributions from upwind states to these receptors.

[96] U.S. Environmental Protection Agency, 2014. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, Research Triangle Park, NC. (*http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf*).

[97] Comprehensive Air Quality Model with Extensions Version 6.20 User's Guide. ENVIRON International Corporation, Novato, CA, March 2015.

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performance results for the 2011 CAMx simulations are within the range found in other recent peer-reviewed and regulatory applications. The model performance results, as described in the AQM TSD, demonstrate that the predictions from the 2011 modeling platform correspond to measured data in terms of the magnitude, temporal fluctuations, and spatial differences for 8-hour daily maximum ozone. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

Comment: The EPA received comments that model performance should be evaluated for the individual days that were used in calculating projected 2017 ozone design values and projected 2017 ozone contributions. Commenters said that, in cases where model performance on these individual days is poor, the impact of the poor performance on projected concentrations and contributions must be investigated and considered in the final results by removing or adjusting these days to account for model bias.

Response: The EPA is using air quality modeling to provide data for a set of representative days with meteorological conditions conducive for ozone formation and transport for use in projecting ozone design values and for calculating the average contribution metric. As described in sections V.D and V.E of this preamble, EPA is using air quality model predictions in a relative sense for estimating 2017 ozone design values and contributions. In this regard, the approach for projecting future design values is ''anchored'' by measured concentrations. As stated in the modeling guidance, it is reasoned that factors causing bias (either under or over-predictions) in the base year will also affect the future case. While good model performance remains a prerequisite for use of a model, problems posed by imperfect model performance on individual days are expected to be reduced when using the relative approach. Moreover, there are no universally accepted, generally applicable numerical bright-line criteria for determining which days might be candidates to exclude or adjust based on model performance for specific days at individual sites, as in the approach suggested by the commenter. Thus, the EPA disagrees that such an approach is necessary or appropriate for determining the sets of days used to provide data for projecting 2017 design values and for calculating the average contribution metric.

The results of the model performance evaluation, as described previously and in the AQM TSD, indicate that ozone predictions from the modeling platform correspond to measured data in terms of the magnitude, temporal fluctuations, and spatial differences for 8-hour daily maximum ozone. Prior court rulings are deferential to modeling choices in this regard. The D.C. Circuit has declined to ''invalidate EPA's predictions solely because there might be discrepancies between those predictions and the real world.'' [98] The fact that a ''model does not fit every application perfectly is not criticism; a model is meant to simplify reality in order to make it tractable.'' [99] The court has held that ''it is only when the model bears no rational relationship to the characteristics of the data to which it is applied that we will hold that the use of the model was arbitrary and capricious.'' [100] As demonstrated by the EPA's model performance evaluation, the modeling platform used in this rulemaking provides reasonable projections of expected future year ozone concentrations and contributions, and is thus an appropriate basis on which to base the findings made in this action.

B. Emission Inventories

The EPA developed emission inventories for this rule including emission estimates for EGUs, non-EGU point sources, stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, wild fires, prescribed fires, and for biogenic emissions that are not the result of human activities. The EPA's air quality modeling relies on this comprehensive set of emission inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

To prepare the emission inventories for air quality modeling, the EPA processed the emission inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 3.7 to produce the gridded, hourly, speciated, model-ready emissions for input to the CAMx air quality model. Additional information on the development of the emission inventories and on data sets used during the emissions modeling process for the final rule are provided in the TSD ''Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform,'' hereafter known as the ''Final Rule Emissions Modeling TSD.'' This TSD is available in the docket for this rule and at *www.epa.gov/air-emissions-modeling/2011-version-6-air-emissions-modeling-platforms*.

The emission inventories, methodologies, and data used for the proposal air quality modeling were provided for public comment in the August 4, 2015 NODA. Comments received on this NODA and on the proposal were considered for the final rule and the resulting data and procedures are documented in the Final Rule Emissions Modeling TSD.

1. Foundation Emission Inventory Data Sets

The EPA developed emission data representing the year 2011 to support air quality modeling of a base year from which future air quality could be forecasted. The primary basis for the 2011 inventories used in air quality modeling was the 2011 National Emission Inventory (NEI) version 2 (2011NEIv2), released in March 2015. Documentation on the 2011NEIv2 is available in the 2011 National Emissions Inventory, version 2 TSD available in the docket for this rule and at *www.epa.gov/air-emissions-inventories/2011-national-emissions-inventory-nei-documentation*. Updates to the 2011NEIv2 were incorporated between the proposed and the final rule in response to comments received on the NODA and on the proposal. The future base case scenario modeled for 2017 includes a representation of changes in activity data and of predicted emission reductions from on-the-books actions, including planned emission control installations and promulgated federal measures that affect anthropogenic emissions.[101] The emission inventories for air quality modeling include sources that are held constant between the base and future years, such as biogenic emissions and emissions from agricultural, wild and prescribed fires. The land use data used for the computation of the biogenic emissions were updated from those used in the proposal modeling to use the 2011 National Land Cover Database (NLCD) along with other updated data sets related to forest species, elevation, and cropland data in response to comments received on the NODA. The

[98] *EME Homer City II,* 795 F.3d at 135–36.

[99] *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994).

[100] *Appalachian Power Co.* v. *EPA,* 135 F.3d 791, 802 (D.C. Cir. 1998).

[101] Biogenic emissions and emissions from wild fires and prescribed fires were held constant between 2011 and 2017 since (1) these emissions are tied to the 2011 meteorological conditions and (2) the focus of this rule is on the contribution from anthropogenic emissions to projected ozone nonattainment and maintenance.

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base and future year emissions for Canada used for the proposed rule were held constant at 2010 levels. For the final rule, the 2010 inventories were updated to reflect closures of EGUs and reductions to onroad and nonroad mobile source emissions in 2017. Emissions for Mexico represent the year 2018 and were unchanged from the proposed rule inventories.

2. Development of Emission Inventories for EGUs

Annual NO_X and SO_2 emissions for EGUs in the 2011NEIv2 are based primarily on data from continuous emission monitoring systems (CEMS), with other EGU pollutants estimated using emission factors and annual heat input data reported to the EPA. For EGUs without CEMS, the EPA used data submitted to the NEI by the states. The final rule inventories include some updates to 2011 EGU stack parameters and emissions made in response to comments on the NODA and proposal. Between proposal and final, additional point sources in the inventory were identified as small EGUs. This resulted in increases to EGU NO_X emissions that were offset by equivalent reductions in non-EGU point source NO_X emissions in Arkansas, California, Florida, Idaho, Louisiana, Mississippi, New Hampshire, Oregon, and Texas. For more information on the details of how the 2011 EGU emissions were developed and prepared for air quality modeling, see the Final Rule Emissions Modeling TSD.

The EPA projected future 2017 baseline EGU emissions using version 5.15 of the Integrated Planning Model (IPM) (*www.epa.gov/airmarkets/power-sector-modeling*). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[102]

To project future 2017 baseline EGU emissions for the CSAPR Update, the EPA adjusted the 2018 IPM version 5.15 base case results to account for three categories of differences between 2017 and 2018.[103] The categories are: (1) Adjusting NO_X emissions for units with SCRs in 2018 but that are assumed not to operate or be installed in 2017; (2) adding NO_X emissions for units that are retiring in 2018 but are projected to operate in 2017; and (3) adjusting NO_X emissions for coal-fired units that are projected to convert to natural gas (*i.e.,* ''coal-to-gas'') in 2018, but are still projected to burn coal in 2017. These adjustments are discussed in greater detail in the IPM documentation found in the docket for this final rule.

The IPM version 5.15 base case accounts for comments received as a result of the NODAs released in 2013, 2014, and 2015. This base case also accounts for comments received on the proposed CSAPR Update as well as updated environmental regulations. Unlike the modeling for the proposed rule, which was conducted prior to the D.C. Circuit's issuance of *EME Homer City II,*[104] this projected base case accounts for compliance with the original CSAPR by including as constraints all original CSAPR emission budgets with the exception of remanded phase 2 NO_X ozone season emission budgets for 11 states and phase 2 NO_X ozone season emission budgets for four additional states that were finalized in the original CSAPR supplemental rule.[105] [106] Specifically, to reflect original CSAPR ozone season NO_X requirements, the modeling includes as constraints the original CSAPR NO_X ozone season emission budgets for 10 states—Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, and Tennessee.

The IPM projected base case also accounts for the effects of the finalized and effective MATS,[107] New Source Review settlements, and on-the-books state rules through February 1, 2016 [108] impacting SO_2, NO_X, directly emitted particulate matter, and CO_2, and final actions the EPA has taken to implement the Regional Haze Rule.[109] The EPA's IPM base case also includes two federal non-air rules affecting EGUs: The Cooling Water Intake Structure (Clean Water Act section 316(b)) rule and the Coal Combustion Residuals (CCR) rule. The IPM modeling performed for the final CSAPR Update does not include the final Clean Power Plan (CPP). Documentation of IPM version 5.15 is in the docket and available online at *www.epa.gov/airmarkets/power-sector-modeling*.

Comment: Many comments requested that the agency not include the CPP in the 2017 projections informing policy decisions in this rule. This was in response to our discussion of this topic and request for comment in the proposal preamble and a memorandum to the docket (hereinafter referred to as the ''Harvey Memo'').[110] Commenters cited discrete CPP-related outputs in the 2017 modeling results, such as the retirement of model plants, for the proposed CSAPR Update and provided

[102] Detailed information and documentation of the EPA's Base Case, including all the underlying assumptions, data sources, and architecture parameters can be found on the EPA's Web site at: *www.epa.gov/airmarkets/power-sector-modeling*.

[103] The EPA uses this approach to project 2017 data because 2017 is not a direct IPM run year.

[104] *EME Homer City Generation, L.P.,* v. *EPA,* No. 795 F.3d 118 (D.C. Cir. 2015).

[105] In *EME Homer City II,* the D.C. Circuit declared invalid the CSAPR phase 2 NO_X ozone season emission budgets of 11 states: Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, and West Virginia. *Id.* 795 F.3d at 129–30, 138. The court remanded those budgets to the EPA for reconsideration. *Id.* at 138. As a result, the EPA removed the original CSAPR phase 2 NO_X ozone season emission budgets as constraints for these 11 states in the 2017 IPM modeling.

[106] The EPA acknowledges that the CSAPR NO_X ozone season emission budgets for Iowa, Michigan, Oklahoma, and Wisconsin—which were finalized in the original CSAPR Supplemental Rule (76 FR 80760, December 27, 2011)—were linked to the same receptors that lead to the remand of other states' NO_X ozone season emission budgets in *EME Homer City II*.

[107] In *Michigan* v. *EPA,* the Supreme Court reversed on narrow grounds a portion of the D.C. Circuit decision upholding the MATS rule, finding that the EPA erred by not considering cost when determining that regulation of EGUs was ''appropriate'' pursuant to CAA section 112(n)(1). 135 S. Ct. 192 (2015). On remand, the D.C. Circuit left the MATS rule in place pending the EPA's completion of its cost consideration in accordance with the Supreme Court's decision. *White Stallion Energy Ctr.* v. *EPA,* No. 12–1100 (Dec. 15, 2015) (order remanding MATS rule without vacatur). The EPA finalized its supplemental action responding to the Supreme Court's Michigan decision on April 14, 2016. 81 FR 24420 (April 25, 2016). The MATS rule is currently in place.

[108] For any specific version of IPM there is a cutoff date after which it is no longer possible to incorporate updates into the input databases.

[109] The EPA did not include the federal Regional Haze Plans for Texas and Oklahoma, published January 5, 2016, in IPM for this rule. These Regional Haze Plans do not require significant emission reductions for three to five years from the effective date of the rule, *see* 81 FR 296, 305. Also, the Fifth Circuit has since stayed those requirements pending judicial review, *Texas* v. *EPA,* 2016 U.S. App. LEXIS 13058 (5th Cir. July 15, 2016).

[110] Reid Harvey, Dir., Clean Air Markets Div., Memorandum to the Docket, Inclusion of the Clean Power Plan in the baseline for the proposed Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS (Dec. 2, 2015) (hereinafter ''Harvey Memo'').

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information indicating that retirements of the actual plants represented in the model were not expected to occur by 2017. Commenters specifically requested that EPA should not include the CPP in the base case modeling.

Response: We agree that the CPP should not be included in the base case modeling for this rule.

The EPA recognizes that, in general, including the illustrative modeling of the CPP, as a promulgated rule, in the baseline of the CSAPR Update would accord with typical practice. This typical practice is one common approach for ensuring that all power sector and air quality impacts evaluated in the CSAPR Update analysis are fully incremental to and independent of the impacts of preceding rules. However, the CSAPR requirements will be implemented at least five years before any requirements are applied to sources under the CPP, and there should be no meaningful impact of the CPP on power sector dispatch decisions in the timeframe of the CSAPR requirements, as analyzed here.[111]

In the Harvey Memo prepared for the CSAPR Update proposal, we identified several key factors and uncertainties associated with measuring the effects of the CPP in 2017. We identified simplifying assumptions in the CPP modeling regarding the types of plans states may develop, and noted that the CPP does not have any pre-2022 requirements for sources and provides states and utilities with ample options to minimize near-term impacts. Harvey Memo, at 11–13. Therefore, we observed that in the context of the CPP, the model projected impacts in 2016–2018 are likely overstated due to the modeling structure's perfect foresight of future prices and market conditions that don't reflect real-world uncertainty. Id. at 6. We also noted the likelihood that states would choose implementation pathways that would completely avoid the actions that were forecast in the model to occur by 2018. For these reasons, the modeling results prior to 2020 were not relied upon for the CPP RIA. Id. at 13.

Commenters, particularly the regulated utilities, by and large agreed that these considerations were significant and atypical and urged the agency to exclude the CPP from the CSAPR Update modeling. Thus, while the EPA continues to believe that the modeling analysis for the CPP in the final CPP RIA was useful and reliable with respect to the model years analyzed for that rule (*i.e.,* 2020, 2025, and 2030), we are excluding the CPP from the base case in this action.

For further discussion of the CPP, see discussion below at Section VII.H.2; see also Harvey Memo, at 5–11.

3. Development of Emission Inventories for Non-EGU Point Sources

The 2011 non-EGU point sources in the 2011 base case inventory match those in the proposal modeling, except for those sources that were updated as a result of comments including sources in Georgia, Illinois, North Carolina, and Oklahoma. Most changes were a result of the reclassification of sources as EGUs and amount to less than 2 percent of the non-EGU point NO_X emissions in each state. The largest change in terms of overall tonnage was 2,800 tons of reduction in Texas, 1,300 of which were offset by increases to the EGU sector and 1,500 tons of which were reductions of railroad equipment emissions based on a comment from the Texas Commission on Environmental Quality. In addition to comments related to emissions, some comments on stack parameters were received and incorporated. Details on the development of the 2011 emission inventories can be found in the Final Rule Emissions Modeling TSD and the 2011NEIv2 TSD.

Prior to air quality modeling, the emission inventories must be processed into a format that is appropriate for the air quality model to use. Details on the processing of the emissions for 2011 and on the development of the 2017 non-EGU emission inventories are available in the Final Rule Emissions Modeling TSD.

Projection factors and percent reductions in this rule reflect comments received as a result of the August 4, 2015 NODA and the proposed CSAPR Update. Non-EGU emissions for 2017 also changed from the proposal due to a correction to the order of precedence for the application of control programs. The largest tonnage change from the projected 2017 NO_X emissions in the proposal was a 2,200 ton increase in Wisconsin, an 8 percent increase. The largest percentage change to 2017 non-EGU point emissions was a 1,300 ton reduction in Oregon equivalent to 9 percent of non-EGU point emissions in the state and offset by an increase in EGU emissions. The 2017 non-EGU point emissions reflect emission reductions due to national and local rules, control programs, plant closures, consent decrees and settlements. Reductions from several Maximum Achievable Control Technology (MACT) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards are included. Projection approaches for corn ethanol and biodiesel plants, refineries and upstream impacts represent requirements pursuant to the Energy Independence and Security Act of 2007 (EISA).

For aircraft emissions at airports, the EPA developed projection factors based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast (TAF) system, published in March 2013.

Point source and nonpoint oil and gas emissions are projected to 2018 [112] using regional projection factors by product type using Annual Energy Outlook (AEO) 2014 projections to year 2018, the year for which all data sources needed to develop the projections were available. NO_X and VOC reductions that are co-benefits to the NESHAP and New Source Performance Standards (NSPS) for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected for select source categories. In addition, Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls are reflected for select source categories. The projection approach for oil and gas emissions was unchanged from that used for the proposal inventories, with the exception of changes incorporated in response to comments in Colorado, Oklahoma, Texas and Utah and due the correction of an error in the projection factors that had been applied at proposal to oil and gas emissions in Kansas. There were modest changes to NO_X emissions in New Mexico and North Dakota as a result of the correction to the order of precedence in the application of control programs. Details on the development of the projected point and nonpoint oil and gas emission inventories are available in the Final Rule Emissions Modeling TSD.

[111] On February 9, 2016, after the close of the public comment period for the CSAPR Update rule, the Supreme Court granted applications to stay the Clean Power Plan, pending judicial review of the rule in the D.C. Circuit, including any subsequent review by the Supreme Court. *West Virginia et al.* v. *EPA,* No. 15A773 (U.S. Feb. 9, 2016). The concerns discussed here predated and are unrelated to the stay. It is currently unclear what adjustments, if any, will need to be made to implementation timing in light of the stay. The Supreme Court's orders granting the stay did not discuss the parties' differing views of whether and how the stay would affect the CPP's compliance deadlines, and they did not expressly resolve that issue. In this context, the question of whether and to what extent tolling is appropriate will need to be resolved once the validity of the CPP is finally adjudicated.

[112] Developing oil and gas sector projections was a very complex process that combined data from many different sources. Not all of the same data was available for 2017, so the projected emissions were retained at 2018 levels as they had been prepared for proposal, but were adjusted based on comments.

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4. Development of Emission Inventories for Onroad Mobile Sources

The EPA developed the onroad mobile source emissions for states other than California using the EPA's Motor Vehicle Emissions Simulator, version 2014a (MOVES2014a), a newer version of MOVES than was used in the proposal modeling. The agency computed the emissions within SMOKE by multiplying the MOVES-based emission factors with the appropriate activity data. The agency also used MOVES emission factors to estimate emissions from refueling. Both 2011 and 2017 onroad mobile source activity data and model databases were updated for Ohio, New Jersey, North Carolina, and Texas in response to comments received on the NODA and on the proposed rule. Additional information on the approach for generating the onroad mobile source emissions is available in the Final Rule Emissions Modeling TSD. Onroad mobile source emissions for California were updated from the proposal using emissions submitted by the state in response to comments on the NODA.

In the future-year modeling for mobile sources, the EPA included all national measures known at the time of modeling. The future scenarios for mobile sources reflect projected changes to fuel usage and onroad mobile control programs finalized as of the date of the model run. In response to comments on the NODA, the EPA developed future year onroad mobile source emission factors and activity data for the final rule modeling that directly represented the year 2017, whereas in the proposal modeling the 2017 emissions were based on adjustments to 2018 emissions. Finalized rules that are incorporated into the mobile source emissions include: Tier 3 Standards (March 2014), the Light-Duty Greenhouse Gas Rule (March 2013), Heavy (and Medium)-Duty Greenhouse Gas Rule (August 2011), the Renewable Fuel Standard (February 2010), the Light Duty Greenhouse Gas Rule (April 2010), the Corporate-Average Fuel Economy standards for 2008–2011 (April 2010), the 2007 Onroad Heavy-Duty Rule (February 2009), and the Final Mobile Source Air Toxics Rule (MSAT2) (February 2007). Impacts of rules that were in effect in 2011 are reflected in the 2011 base year emissions at a level that corresponds to the extent to which each rule had penetrated into the fleet and fuel supply by the year 2011. Local control programs such as the California LEV III program are included in the onroad mobile source emissions. Activity data for onroad mobile sources was projected using AEO 2014. Updated onroad mobile source emissions in California for the final rule modeling of the year 2017 were provided by the California Air Resources Board.

5. Development of Emission Inventories for Commercial Marine Category 3 (Vessel)

The commercial marine category 3 vessel (''C3 marine'') emissions in the 2011 base case emission inventory for this rule are consistent with those in the proposal modeling and are equivalent to those in the 2011NEIv2. These emissions reflect reductions associated with the Emissions Control Area proposal to the International Maritime Organization control strategy (EPA–420–F–10–041, August 2010); reductions of NO_X, VOC, and CO emissions for new C3 engines that went into effect in 2011; and fuel sulfur limits that went into effect as early as 2010. The cumulative impacts of these rules through 2017 are incorporated in the 2017 projected emissions for C3 marine sources.

6. Development of Emission Inventories for Other Nonroad Mobile Sources

To develop the nonroad mobile source emission inventories other than C3 marine for the modeling platform, the EPA used monthly, county, and process level emissions output from the National Mobile Inventory Model (NMIM) (*http://www.epa.gov/otaq/nmim.htm*). State-submitted emissions data for nonroad sources were used for Texas and California. For Texas, these emissions are consistent with those in the 2011NEIv2, while the California emissions were consistent with those used in the proposal modeling. Locomotive emissions in Texas and North Carolina in the final rule modeling incorporated updates in response to comments received on the NODA.

In response to comments received on the NODA and the proposal, the EPA used NMIM to project nonroad mobile emissions directly to 2017, as opposed to adjusting 2018 emissions back to 2017 as was done for the proposal modeling. The nonroad mobile emission control programs include reductions to locomotives, diesel engines and marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of control programs included for mobile sources is available in the Final Rule Emissions Modeling TSD.

7. Development of Emission Inventories for Nonpoint Sources

The emissions for stationary nonpoint sources in the 2011 base case emission inventory are largely consistent with those in the proposal modeling and in the 2011NEIv2, although some updates to Connecticut, Massachusetts, North Carolina, Texas and also to portable fuel container emissions were made in response to comments on the NODA and the proposal. For more information on the nonpoint sources in the 2011 base case inventory, see the Final Rule Emissions Modeling TSD and the 2011NEIv2 TSD.

Where states provided the EPA with information about projected control measures or changes in nonpoint source emissions, the EPA incorporated those inputs in its projections. Updates to nonpoint emissions in North Carolina, Connecticut, Massachusetts, and Texas were incorporated in response to comments received on the NODA. The EPA included adjustments for state fuel sulfur content rules for fuel oil in the Northeast. Projected emissions for portable fuel containers reflect the impact of projection factors required by the final Mobile Source Air Toxics (MSAT2) rule and the EISA, including updates to cellulosic ethanol plants, ethanol transport working losses, and ethanol distribution vapor losses.

For the final rule, emissions for nonpoint oil and gas sources were updated in Colorado, Texas, and Oklahoma in response to comments received on the 2015 NODA, and an error was corrected in the projections for Kansas. The EPA developed regional projection factors for nonpoint oil and gas sources by product type based on Annual Energy Outlook (AEO) 2014 projections to year 2018. The agency reflected criteria air pollutant (CAP) co-benefit reductions resulting from the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE) and NSPS rules and Oil and Gas NSPS VOC controls for select source categories. Additional details on the projections are available in the Final Rule Emissions Modeling TSD.

C. Definition of Nonattainment and Maintenance Receptors

In this section, the EPA describes how it determines locations where nonattainment or maintenance problems are expected for the 2008 8-hour ozone NAAQS in the 2017 analytic future year chosen for this rule. The EPA then describes how it factored current monitored data into the identification of sites as having either nonattainment or maintenance concerns for the purposes of this rulemaking. These sites are used as the ''receptors'' for quantifying the contributions of emissions in upwind states to nonattainment and

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maintenance concerns in downwind locations.

In this rule, the EPA is relying on the CSAPR approach (as described below) to identify separate nonattainment and maintenance receptors in order to give independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[113] In its decision on remand from the Supreme Court, the D.C. Circuit confirmed that the EPA's approach to identifying maintenance receptors in CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136.

In CSAPR, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS. The EPA separately identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that takes into account historical variability in air quality at that receptor. The original CSAPR approach for identifying nonattainment and maintenance receptors relied only upon air quality model projections of measured design values. In the original CSAPR, if the average design value in the analysis year was projected to exceed the NAAQS, then the monitoring site was identified as a nonattainment receptor without consideration of whether the monitoring site is currently measuring ''clean data'' (*i.e.,* design values below the NAAQS based on the most recent three years of measured data). In prior transport rulemakings, such as the NO_X SIP Call and CAIR, the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.[114] The EPA explained that it had the most confidence in its projections of nonattainment for those counties that also measure nonattainment for the most recent period of available ambient data. In the original CSAPR, the EPA was compelled to deviate from this practice of incorporating monitored data into its evaluation of projected nonattainment receptors because the most recent monitoring data then available reflected large emission reductions from CAIR, which the original CSAPR was designed to replace. As recently affirmed by the D.C. Circuit, it was therefore reasonable for the EPA to decide not to compare monitored data reflecting CAIR emissions reductions to its modeling projections that instead excluded CAIR from its baseline.[115]

As the EPA is not replacing an existing transport program in this CSAPR Update, the agency proposed to once again consider current monitored data as part of the process for identifying projected nonattainment receptors for this rulemaking. The agency received comments supporting the consideration of current monitored data for identifying projected nonattainment receptors. Thus, for the final CSAPR Update the EPA is identifying as nonattainment receptors those monitors that both currently measure nonattainment and that the EPA projects will be in nonattainment in 2017.

As noted previously, in the original CSAPR, the EPA identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that takes into account historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant base year period.

The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor. The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. Therefore, the maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur. The projected maximum design value is used to identify upwind states whose emissions, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

For the final CSAPR Update, the EPA assesses the magnitude of the maximum projected design value for 2017 at each receptor in relation to the 2008 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determines that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II.*[116] That is, monitoring sites with a maximum projected design value that exceeds the NAAQS are projected to have a maintenance problem in 2017.

In addition, those sites that are currently measuring clean data, but are projected to be nonattainment based on the average design value (and that, by definition, are projected to have a maximum design value above the standard) are also identified as maintenance-only receptors. Unlike nonattainment receptors, current clean monitored data does not disqualify a receptor from being identified as a maintenance receptor because the possibility of failing to maintain the NAAQS in the future, even in the face of current attainment of the NAAQS, is exactly what the maintenance prong of the good neighbor provision is designed to guard against.

Comment: The agency received comments that the EPA should not include as a downwind receptor any site that is currently measuring clean data. Commenters also raise concerns with the EPA's reliance on the projected maximum design value to determine whether an area should be identified as a maintenance receptor, particularly where the projected average design value is below the NAAQS. The commenters contend that this approach does not take into account the nationwide trend toward decreasing ozone design values and improving ozone air quality.

Response: The EPA disagrees with this comment based on several factors. First, current (*i.e.,* 2013–2015) ozone design values in many portions of the eastern U.S. may be lower than what might otherwise have been expected due to cooler than normal temperatures during the summers of 2013, 2014, and 2015 which led to meteorological conditions which were generally unfavorable for the formation of high ozone concentrations. An examination of historical inter-annual variability in summer meteorological conditions in the East indicates that in spite of the

[113] 531 F.3d at 910–911 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[114] 63 FR at 57375, 57377 (Oct. 27, 1998); 70 FR at 25241 (May 12, 2005). *See also North Carolina,* 531 F.3d at 913–914 (affirming as reasonable the EPA's approach to defining nonattainment in CAIR).

[115] *EME Homer City II,* 795 F.3d at 135–36; *see also* 76 FR 48208 at 48230–31 (August 8, 2011).

[116] *See* 795 F.3d at 136.

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relatively non-conducive meteorological conditions seen in the last 3 years, conditions more favorable to ozone formation have often occurred in the past and are likely to reoccur in the future, therefore leading to the risk of a violation of the NAAQS. *See* the AQM TSD for more details.

Second, ambient monitoring data for maintenance sites that are currently measuring attainment suggest that these sites are at risk of violating the NAAQS. Table V.D–3 provides the 2013–2015 design values and the 4th highest annual 8-hour daily maximum ozone concentrations used to calculate these design values for each of the maintenance receptors that are currently measuring attainment. The data in Table V.D–3 indicate (1) seven of the nine sites had measured 4th high values [117] which exceed the level of the NAAQS in at least one of the years during this 3-year time period and (2) 4th high ozone concentration increased from 2014 to 2015 at all but one of these sites. There were increases in measured 4th high values between 2013 and 2015 at all but one of these sites (with the highest increase of 22 ppb occurring in Harris County TX), despite the fact that ozone precursor emissions are continuing to trend downward.[118] In addition, preliminary monitoring for 2016 also indicates that ozone has increased, based on 4th high values, in 2016 compared to the concentrations that were measured in 2014 at most of the receptor sites.[119] This shows that the influence of meteorology on measured ozone values can overwhelm the general downward trend in emissions. Thus, given the variability of meteorological conditions, there is every reason to believe that these maintenance sites that are currently measuring attainment are at risk of violating the NAAQS in 2017, as projected by the EPA's modeling.

The EPA believes it is therefore appropriate and reasonable to use the maximum design value to identify receptors that may have maintenance problems in the future. This approach uses measured data in order to establish potential air quality outcomes at each receptor that take into account the variable meteorological conditions present across the entire period of measured data (2009 to 2013). The EPA interprets the maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor. The EPA construes the average design value at a receptor to be a reasonable projection of future air quality in that area under ''average'' conditions. However, the EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, air mass patterns) that promote ozone formation, may recur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, recur. It also identifies upwind emissions that under those circumstances could interfere with the downwind area's ability to maintain the NAAQS.

D. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

The following is a brief summary of the procedures for projecting future-year 8-hour ozone average and maximum design values to 2017 to determine nonattainment and maintenance receptors. Consistent with the EPA's modeling guidance the agency uses the air quality modeling results in a ''relative'' sense to project future concentrations. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values [120] up or down depending on the relative (percent) change in model predictions for each location. The modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under ''average'' conditions. Because the base year for this rule is 2011, the EPA is using the base period 2009–2013 ambient ozone design value data in order to project 2017 average design values in a manner consistent with the modeling guidance.

The approach for projecting future ozone design values involved the projection of an average of up to 3 design value periods, which include the years 2009–2013 (design values for 2009–2011, 2010–2012, and 2011–2013). The 2009–2011, 2010–2012, and 2011–2013 design values are accessible at *www.epa.gov/airtrends/values.html.* The average of the 3 design values creates a ''5-year weighted average'' value. The 5-year weighted average values were then projected to 2017. To project 8-hour ozone design values, the agency used the 2011 base year and 2017 future base-case model-predicted ozone concentrations to calculate relative response factors (RRFs) for the location of each monitoring site. The RRFs were applied to the 2009–2013 average ozone design values and the individual design values for 2009–2011, 2010–2012, and 2011–2013. Details of this approach are provided in the AQM TSD.

Projected design values that are greater than or equal to 76.0 ppb are considered to be violating the NAAQS in 2017. As noted previously, nonattainment receptors are those sites that are violating the NAAQS based on the most recent measured air quality data and also have projected average design values of 76.0 ppb or greater. Therefore, as an additional step, for those sites that are projected to be violating the NAAQS based on the average design values in 2017, the EPA examined the most recent measured design value data to determine if the site was currently violating the NAAQS. For the final rule, the agency examined ambient data for the 2013–2015 period, which is the most recent available measured design values at the time of this rule.

Maintenance-only receptors therefore include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data, and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 76.0 ppb or greater. The EPA notes that the 2017 ozone nonattainment receptors are inclusive of areas that, in addition to having projected nonattainment, may have maintenance issues in the future, since the maximum design values for each of these sites is always greater than or equal to the average design value.

Table V.D–1 contains the ambient 2009–2013 base period average and maximum 8-hour ozone design values, the 2017 projected baseline average and maximum design values, and the ambient 2013–2015 design values for the 6 sites in the eastern U.S. projected to be 2017 nonattainment receptors. Table V.D–2 contains this same information for the 13 maintenance-only sites in the eastern U.S. The design

[117] Ozone season measured daily 4th high 8-hour average ozone concentrations are used to calculate design values. The design value is a 3 year average of the 4th high values. See 40 CFR part 50, Appendix P to Part 50.

[118] *See* the AQM TSD.

[119] This is based on preliminary 2016 data available from the Air Quality System (AQS) and AirNow as of August 23, 2016, which represents only a portion of the ozone season. This data has not been certified by state agencies.

[120] The ozone design value at a particular monitoring site is the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration at that site. See 40 CFR part 50, Appendix P to Part 50.

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values for all monitoring sites in the U.S. are provided in docket.

TABLE V.D–1—AVERAGE AND MAXIMUM 2009–2013 AND 2017 BASELINE 8-HOUR OZONE DESIGN VALUES AND 2013–2015 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT SITES IN THE EASTERN U.S.

[Nonattainment receptors]

Monitor ID	State	County	Average design value 2009–2013	Maximum design value 2009–2013	Average design value 2017	Maximum design value 2017	2013–2015 design value
090019003	Connecticut	Fairfield	83.7	87	76.5	79.5	84
090099002	Connecticut	New Haven	85.7	89	76.2	79.2	78
480391004	Texas	Brazoria	88.0	89	79.9	80.8	80
484392003	Texas	Tarrant	87.3	90	77.3	79.7	76
484393009	Texas	Tarrant	86.0	86	76.4	76.4	78
551170006	Wisconsin	Sheboygan	84.3	87	76.2	78.7	77

TABLE V.D–2—AVERAGE AND MAXIMUM 2009–2013 AND 2017 BASELINE 8-HOUR OZONE DESIGN VALUES AND 2013–2015 DESIGN VALUES (ppb) AT SITES IN THE EASTERN U.S. THAT ARE PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	Average design value 2009–2013	Maximum design value 2009–2013	Average design value 2017	Maximum design value 2017	2013–2015 design value
090010017	Connecticut	Fairfield	80.3	83	74.1	76.6	81
090013007	Connecticut	Fairfield	84.3	89	75.5	79.7	83
211110067	Kentucky	Jefferson	85.0	85	76.9	76.9	[121] N/A
240251001	Maryland	Harford	90.0	93	78.8	81.4	71
260050003	Michigan	Allegan	82.7	86	74.7	77.7	75
360850067	New York	Richmond	81.3	83	75.8	77.4	74
361030002	New York	Suffolk	83.3	85	76.8	78.4	72
390610006	Ohio	Hamilton	82.0	85	74.6	77.4	70
421010024	Pennsylvania	Philadelphia	83.3	87	73.6	76.9	73
481210034	Texas	Denton	84.3	87	75.0	77.4	83
482010024	Texas	Harris	80.3	83	75.4	77.9	79
482011034	Texas	Harris	81.0	82	75.7	76.6	74
482011039	Texas	Harris	82.0	84	76.9	78.8	69

TABLE V.D–3—AMBIENT OZONE DESIGN VALUES FOR 2013–2015 AND THE 4TH HIGHEST 8-HOUR DAILY MAXIMUM OZONE CONCENTRATIONS (ppb) FOR EACH MAINTENANCE-ONLY RECEPTOR THAT IS CURRENTLY MEASURING ATTAINMENT

Monitor ID	State	County	2013–2015 design value	2013 4th highest value	2014 4th highest value	2015 4th highest value
211110067	Kentucky	Jefferson	N/A	N/A	70	* 76
240251001	Maryland	Harford	71	72	67	74
260050003	Michigan	Allegan	75	* 78	* 77	72
360850067	New York	Richmond	74	69	68	* 77
361030002	New York	Suffolk	72	72	66	* 78
390610006	Ohio	Hamilton	70	69	70	72
421010024	Pennsylvania	Philadelphia	73	68	72	* 79
482011034	Texas	Harris	74	69	66	* 88
482011039	Texas	Harris	69	69	63	* 77

* Indicates 4th highest values that exceed the NAAQS.

Comment: The EPA received comments on the approach for projecting future year design values for monitoring sites located in certain coastal areas (*i.e.,* monitoring sites located in southern Connecticut along Long Island Sound, in Wisconsin and Michigan along Lake Michigan and in Maryland along the Chesapeake Bay).

[121] The 2013–2015 design value at this site is not valid due to incomplete data for 2013. There are valid 4th high measured concentrations for 2014 and 2015 and therefore the site may have valid design value data when the 2014–2016 data is complete. The 2014 4th high value at this site was 70 ppb and the 2015 4th high value at this site was 76 ppb. In addition, there is one other monitoring site in Jefferson County KY which has a valid 2013–2015 design value of 66 ppb. There is one other site in the Louisville CBSA which has a slightly higher 2013–2015 design value of 68 ppb (site 211850004 in Oldham County KY). Since there is no valid design value data that indicates that the Jefferson County receptor or any other monitoring site in Jefferson County or the Louisville metropolitan area is currently exceeding the 2008 NAAQS, for the purposes of this final rule, the Jefferson County KY receptor will be considered a maintenance receptor.''

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Some commenters said that the relative response factors for coastal sites should be based on modeled ozone in the grid cell containing the monitoring site or ''land'' cells only, rather than the grid cell with the highest 2011 base case modeled value from among the 3 by 3 matrix of grid cells surrounding the monitoring site (*i.e.,* the 3 x 3 matrix approach). Some commenters said that using the 3 x 3 approach for coastal sites can result in the use of modeled data from grid cells over water, which the commenters claim are not representative of the location of the monitor. These commenters contend that modeled values from ''over water'' cells are biased high and will overstate projected 2017 design values at coastal sites. In this regard, the commenters said EPA should consider using the modeled data in the grid cell containing the monitoring site or use the highest value in ''over land'' grid cells adjacent to the monitoring site.

Commenters examined model performance in the grid cell that contained the monitor and also compared these measured values to the ''highest'' modeled value in the 3 x 3 grid cell matrix surrounding the monitoring site. They contend that higher modeled ozone concentrations from the 3 x 3 matrix overstate concentrations measured at the monitoring site and, as a result, commenters claim that using the 3 x 3 modeled values will lead to inaccurate future model projections.

Response: EPA first notes that the modeling guidance recommends calculating relative response factors based on the highest values in the vicinity of the monitoring site (*i.e.,* the 3 x 3 matrix approach) in part because limitations in the inputs and model physics can affect model precision at the grid cell level. Allowing some leeway in the precision of the predicted location of daily maximum ozone concentrations can help assure that possibly artificial, fine scale variations do not inadvertently impact an assessment of modeled ozone response. In addition, monitors are sometimes located very close to the border of two or more grid cells. For both of these reasons, choosing to calculate the model response from the nearby grid cell with the highest modeled ozone value is likely to be most representative of model response during high measured ozone conditions. In addition, coastal sites by the nature of their location near large water bodies often measure ozone concentrations in air from over the water when winds are blowing from the water to the land. Such wind flows can occur as part of a broader ''synoptic scale'' wind pattern and/or during more local scale onshore wind flows associated with a ''sea breeze'', ''sound breeze'', ''lake breeze'', or ''bay breeze'' depending on the nature of the adjacent body of water. Thus, it is appropriate to consider modeled values from both ''over water'' and ''over land'' grid cells to represent ozone concentrations which may impact monitoring sites in coastal areas.

The commenters also compared measured ozone values at monitoring locations to the highest modeled concentrations in the 3 x 3 grid cells surrounding the monitor and found that modeled ozone in grid cells over the water (where there are no monitoring sites) often ''over predicted'' the measured values at the monitors. The commenters claim that this will lead to an overstatement of future year design values and inaccurate future year values. The EPA finds no basis for this conclusion. First, the components of the modeling system used for this final rule, (*i.e.,* the photochemical grid model, the meteorological model, emissions models, and input data) are based on state-of-the-science methods and data that are designed to represent the physical and chemical processes associated with the formation, transport, and fate of ozone and precursor pollutants. The intent of the model evaluation is to use available measurements to gain confidence in the use of the modeling system not only to predict concentrations for times and locations where there are measurements, but also to provide credible estimates of base year concentrations in other locations which can be used to project future year concentrations. Second, the EPA is not using the absolute modeled concentrations to determine future year (2017) design values. As described in the preamble and the AQM TSD, the EPA projects future year design values based on the percent change (*i.e.,* relative response) in ozone using predictions from a model simulation for 2011 and predictions from a corresponding model simulation for 2017. The relative response factors based on the modeled data from the 3 x 3 matrix approach are applied to measured ozone design value.

For the final rule, the EPA performed an analysis that compared the 2017 projected design values based on applying the 3 x 3 matrix approach recommended in EPA's modeling guidance to an approach that relies exclusively on modeled values in the grid cell containing the monitoring (*i.e.,* monitor-cell approach). This analysis was performed for ozone monitoring sites nationwide including the coastal sites of concern to commenters. A data file with the projected 2017 design values using the 3 x 3 matrix approach and the monitor-cell approach at individual monitoring sites can be found in the docket.

In our analysis we examined the data separately for each of four groupings of monitoring sites: (1) All sites nationwide, (2) all sites in the East, (3) all nonattainment and maintenance receptors identified in this rule, and (4) the set of coastal sites of particular concern to the commenters together with a coastal site in Harford Co., MD that is also receptor for this final rule. The specific set of 8 coastal sites analyzed as a separate group include Fairfield Co., CT sites 090010017, 090013007, and 090019003, New Haven Co., CT 090093002, Baltimore Co., MD 240053001, Harford Co., MD 240251001, Allegan Co., MI, 260050003, and Sheboygan Co, WI 551170006. Note that all of these sites, except for the site in Baltimore Co., MD are receptors for this final rule. The results indicate that the 3 x 3 approach results in lower or equivalent projected 2017 design values compared to the monitor-cell approach at 76 percent of the monitoring sites nationwide. That is, at a majority of the monitoring sites, the 3 x 3 approach which relies on the highest base year concentrations in the vicinity of the monitoring site tends to be more responsive to emissions reductions than only using data from the grid cell containing the monitor. For the Eastern U.S., 75 percent of the monitoring sites had lower projected 2017 design values with the 3 x 3 approach, compared to the monitor-cell approach. At 14 of the 19 nonattainment and maintenance receptors for this rule, the 3 x 3 approach design value is either lower or within 0.5 ppb [122] of the corresponding value from the monitor-cell approach. Finally, for the 8 coastal sites, the 3 x 3 approach on balance does not result in an overall notable bias compared to the monitor-cell approach. Specifically, at half of these sites the 3 x 3 approach design value is lower or within 0.5 ppb of the corresponding value from the monitor-cell approach. EPA does not believe that it would be appropriate to use the 3 x 3 approach for some coastal receptors and the single monitor-cell approach for other coastal receptors, depending solely on the outcome as to which approach yields lower future design value at an individual receptor site. Based on the results of this analysis

[122] ''In this analysis ''within 0.5 ppb'' includes values that greater than or equal to -0.5 ppb and also less than or equal to 0.5 ppb.

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the EPA continues to believe that the 3 x 3 approach is appropriate for projecting design values for this rule and provides for regional consistency in the projection methodology across all sites.

Comment: Commenters contend that the EPA is not appropriately considering international emissions in the process of identifying downwind nonattainment and maintenance receptors. The commenters cite CAA section 179B and contend that it requires the Administrator to approve plans that would be sufficient to attain or maintain the NAAQS but for emissions emanating from outside of the U.S. They therefore contend that, where a receptor in the EPA's modeling would attain or maintain the standard when international emissions are accounted for, the EPA has no authority to require emissions from upwind states pursuant to section 110(a)(2)(D)(i)(I). Commenters state that such reduction requirements would constitute the over-control of emissions from upwind states.

The commenters explicitly recommend that the EPA exclude the projected contributions from Canada and Mexico from the projected design values before comparing the projections to the NAAQS for purposes of identifying receptors. Commenters further recommend that the EPA exclude a ''conservatively calculated'' 5 percent of EPA-estimated contributions attributable to the anthropogenic fraction of boundary concentrations. The commenters propose that this approach would result in fewer receptors and relieve upwind states of the obligation to make emission reductions associated with these receptors.

Response: The EPA disagrees with commenters that section 179B of the Clean Air Act obviates the good neighbor obligations imposed upon states by section 110(a)(2)(D)(i)(I) of the Act.

First, commenters misunderstand the provisions of section 179B. Section 179B permits the EPA to approve an attainment plan or plan revision for areas that could attain the relevant NAAQS by the statutory attainment date ''but for'' emissions emanating from outside the U.S. When applicable, this CAA provision relieves states from imposing control measures on emissions sources in the state's jurisdiction beyond those necessary to address reasonably controllable emissions from within the U.S. Specifically, CAA section 179B(a) provides that the EPA shall approve a plan for such an area if: (i) The plan meets all other applicable requirements of the CAA, and (ii) the submitting state can satisfactorily demonstrate that ''but for emissions emanating from outside the United States,'' the area would attain and maintain the relevant NAAQS. In addition, CAA section 179B(b) applies specifically to the ozone NAAQS and provides that if a state demonstrates that an ozone nonattainment area would have timely attained the NAAQS by the applicable attainment date ''but for emissions emanating from outside of the United States,'' then the area can avoid extension of the ozone attainment dates pursuant to CAA section 181(a)(5), the application of fee provisions of CAA section 185, and the mandatory reclassification provisions under CAA section 181(b)(2) for areas that fail to attain the ozone NAAQS by the applicable attainment date.

Commenters fail to acknowledge that, even if an area is impacted by emissions from outside the U.S., CAA section 179B does not affect the designations process. The designations process is meant to protect public health and welfare. Designating an area nonattainment for a particular NAAQS ensures that the public is informed that the air quality in a specific area exceeds the standard. Congress determined that in nonattainment areas, there should be adequate safeguards to protect public health and welfare. For example Congress required such areas to have nonattainment new source review permitting programs, to ensure that air quality is not further degraded. Accordingly, areas with design values above the NAAQS are designated nonattainment and classified with a classification as indicated by actual ambient air quality. As a result of designation and classification, the state is subject to the applicable requirements, including nonattainment new source review, conformity, and other measures prescribed for nonattainment areas by the CAA. Section 179B of the CAA does not provide for any relaxation of mandatory emissions control measures (including contingency measures) or the prescribed emissions reductions; it only eliminates the obligation for an attainment demonstration that demonstrates attainment and maintenance of the NAAQS, which is conditioned upon the state meeting all other attainment plan requirements, and voids certain consequences of an area's failure to attain, including mandatory reclassifications.

CAA section 179B also does not alter the CAA's general construct expressed in subpart 1 of part D that states with nonattainment areas are expected to adopt reasonable emissions controls to lessen emissions of criteria pollutants to promote citizen health protection. The construct ensures that states will take reasonable actions to mitigate the public health impacts of exposure to ambient levels of pollution that violate the NAAQS by imposing reasonable control measures on the sources that are within the jurisdiction of the state regardless of impacts from interstate or international emissions. The primary purpose of part D of Title I of the CAA is to achieve emission reductions so that people living in a nonattainment area receive the public health protection intended by the NAAQS.

In sum, section 179B provides an important tool that provides states relief from the requirement to demonstrate attainment—and from the more stringent planning requirements that would result from failure to attain—in areas where, even though the air agency has taken appropriate measures to address air quality in the influenced area, emissions from outside of the U.S. prevent attainment. The provision does not absolve states of the obligation to impose reasonable emission controls even where states can demonstrate that the area would attain ''but for'' the impact of international emissions. The commenters do not explain why, given the obligation of downwind states with designated nonattainment areas to impose reasonable controls on emissions, upwind states should not also be subject to a similar obligation to take certain reasonable steps to reduce emissions impacting those downwind areas.

The commenters have not explained why the terms of section 179B require its application to EPA's evaluation of upwind state's interstate transport obligations. Section 179B is located in subpart D of title I, which addresses plan requirements for designated nonattainment areas. As just described, the specific terms of section 179B outline which nonattainment area requirements will and will not apply upon approval of a section 179B demonstration, none of which apply directly to upwind states via section 110(a)(2)(D)(i)(I). In particular, the good neighbor provision does not require upwind areas to ''demonstrate attainment and maintenance'' of the NAAQS. Rather, the statute requires upwind states to prohibit emissions which will ''contribute significantly to nonattainment'' or ''interfere with maintenance'' of a NAAQS. As discussed further in section IV.B.1, while upwind states must address their fair share of downwind air quality problems, the EPA has not interpreted this provision to hold upwind areas

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responsible for bringing downwind areas into attainment. Therefore, the relief provided by section 179B(a) and (b) from the obligation to demonstrate attainment, extension of the attainment date, and mandatory reclassifications, is simply not applicable to downwind states.

Even if section 179B were in some manner applicable to upwind states' transport obligations, the EPA does not believe that the contribution of international emissions should impact EPA's identification of downwind nonattainment and maintenance receptors affected by the interstate transport of emissions. These receptors represent areas that the EPA projects will have difficulty attaining and maintaining the NAAQS, and which therefore require adequate safeguards to protect public health and welfare. The EPA therefore does not agree that, when identifying downwind air quality problems for purposes of interstate transport, section 179B requires that we subtract the contributions of international emissions from the projected design values. This would be inconsistent with EPA's approach to area designations and is simply not required by the plain language of the statute. Moreover, such an interpretation would allow downwind and upwind areas to make no efforts to address clear violations of the NAAQS, leaving the area's citizens to suffer the health and environmental consequences of such inaction.

Moreover, just as any state with a nonattainment area—including downwind states—must take reasonable steps to control emissions even where an area is impacted by international emissions, the EPA believes that it is appropriate for upwind states to also adopt reasonable emissions controls to lessen the impact of emissions generated in their state and subsequently transported to downwind areas. As noted in Section IV of the preamble, the EPA does not view the obligation under the good neighbor provision as a requirement for upwind states to bear all of the burden for resolving downwind air quality problems. Rather, it is an obligation that upwind and downwind states share responsibility for addressing air quality problems. If, after implementation of reasonable emissions reductions by an upwind state, a downwind air quality problem persists, whether due to international emissions or emissions originating within the downwind state, the EPA can relieve the upwind state of the obligation to make additional reductions to address that air quality problem. But the statute does not absolve the upwind state of the obligation to make reasonable reductions in the first instance.

The EPA took just such an approach in the original CSAPR rulemaking when calculating annual SO_2 emissions budgets for states linked to downwind $PM_{2.5}$ air quality problems. There, the EPA imposed budgets based on a level of control stringency equivalent to \$2,300 per ton of SO_2 emissions. Despite the persistence of downwind air quality problems to which certain upwind states were linked, the EPA concluded that this level of control stringency represented the upwind states' full transport obligation with respect to the $PM_{2.5}$ standards and additional controls were not reasonable because significant reductions could not be achieved at higher costs. 76 FR 48208, 48257–259.

Accordingly, the EPA also does not agree that imposing emission reductions on upwind states linked to areas affected by international emissions based on the implementation of reasonable control measures would result in over-control. As discussed in section VII.D of the preamble, the emissions reductions required by this rulemaking are based on relatively modest investments in turning on and optimizing already existing SCRS and installing a limited amount of combustion controls, which is feasibly and reasonably achieved by the 2017 ozone season. Moreover, the emissions reductions required by this rulemaking do not fully resolve most of the air quality problems identified in this rule. As discussed further in section VI.D, the D.C. Circuit has identified those circumstances that would constitute over-control pursuant to CAA section 110(a)(2)(D)(i)(I), and those circumstances are not present here.

E. Pollutant Transport From Upwind States

1. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on 2017 8-hour design values for identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors (NO_X and VOC) to ozone for individual receptor locations. The strength of the photochemical model source apportionment technique is that all modeled ozone at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique [123] to quantify the contribution of 2017 baseline NO_X and VOC emissions from all sources in each state to projected 2017 ozone concentrations at air quality monitoring sites. The EPA continues to believe that the OSAT/APCA tool is the most appropriate source apportionment technique for quantifying contributions for the purposes of this rule because it is constructed to provide source culpability data to inform the design of emissions control strategies.[124] In the source apportionment model run, the EPA tracked the ozone formed from each of the following contribution categories (*i.e.,* ''tags''):

- States—anthropogenic NO_X and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);
- Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);
- Boundary Concentrations—concentrations transported into the modeling domain;
- Tribes—the emissions from those tribal lands with point source inventory data in the 2011 NEI (contributions from individual tribes were not modeled);
- Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (contributions from Canada and Mexico were not modeled separately);
- Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and
- Offshore—combined emissions from offshore marine vessels and offshore drilling platforms (*i.e.,* not by state).

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions

[123] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

[124] Comprehensive Air Quality Model with Extensions Version 6.20 User's Guide. ENVIRON International Corporation, Novato, CA, March 2015.

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in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wild fire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. The contributions from the ''biogenic'', ''offshore'', and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected 2017 baseline emissions and 2011 meteorology for this time period. The hourly contributions [125] from each tag were processed to obtain the 8-hour average contributions corresponding to the time period of the 8-hour daily maximum concentration on each day in the 2017 model simulation. This step was performed for those model grid cells containing monitoring sites in order to obtain 8-hour average contributions for each day at the location of each site. The model-predicted contributions on the days with high modeled concentrations in 2017 were then applied in a relative sense to quantify the contributions to the 2017 average design value at each site. The resulting 2017 average contributions from each tag to each monitoring site in the eastern and western U.S. along with additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the AQM TSD.

The average contribution metric is intended to provide a reasonable representation of the contribution from individual states to the projected 2017 design value, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner is beneficial since the magnitude of the contributions is directly related to the magnitude of the design value at each site.

The largest contribution from each state in the East to any single 8-hour ozone nonattainment receptor in a downwind state is provided in Table V.E–1. The largest contribution from each state in the East to any single 8-hour ozone maintenance-only receptor in a downwind state is also provided in Table V.E–1.

TABLE V.E–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS FOR EACH STATE IN THE EASTERN U.S.

Upwind state	Largest downwind contribution to nonattainment receptors (ppb)	Largest downwind contribution to maintenance receptors (ppb)
AL	0.99	0.73
AR	1.00	2.07
CT	0.00	0.46
DE	0.38	1.32
DC	0.07	0.86
FL	0.71	0.75
GA	0.60	0.62
IL	17.90	23.61
IN	6.49	12.32
IA	0.58	0.81
KS	1.13	1.22
KY	0.68	10.88
LA	3.01	3.20
ME	0.00	0.01
MD	2.12	5.22
MA	0.12	0.06
MI	2.62	1.27
MN	0.40	0.36
MS	0.81	0.79
MO	1.67	3.78
NE	0.35	0.27
NH	0.02	0.02
NJ	9.52	11.90
NY	18.50	18.81
NC	0.51	0.50
ND	0.06	0.22
OH	1.83	3.78
OK	2.24	1.62
PA	9.28	14.61
RI	0.03	0.01
SC	0.15	0.30
SD	0.08	0.12
TN	0.50	1.82
TX	2.18	2.64
VT	0.01	0.01
VA	1.92	5.21
WV	1.04	3.31
WI	0.33	2.52

2. Application of Screening Threshold

Once the EPA has quantified the magnitude of the contributions from each upwind state to downwind nonattainment and maintenance receptors, it then uses an air quality screening threshold to identify upwind states that contribute to downwind ozone concentrations in amounts sufficient to ''link'' them to the downwind nonattainment and maintenance receptors and justify further analysis of potential emission reductions to address significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS in other states. As discussed previously in section IV, the EPA is establishing an air quality screening threshold calculated as one percent of the 2008 ozone NAAQS. Specifically, the agency has calculated an 8-hour ozone value for this air quality threshold of 0.75 ppb.

States in the East [126] whose contributions to a specific receptor meet or exceed the screening threshold are considered linked to that receptor; those states' ozone contributions and emissions (and available emission reductions) are analyzed further, as described in section VI, to determine whether and what emissions reductions might be required from each state. States in the East whose contributions are below the threshold are not included in the rule and are considered to make insignificant contributions to projected downwind air quality problems. Accordingly, as discussed in section IV, the EPA has determined that sources in these states need not make any further emissions reductions in order to address the good neighbor provision with respect to the 2008 ozone NAAQS.

Based on the maximum downwind contributions identified in Table V.E–1, the following states contribute at or above the 0.75 ppb threshold to downwind nonattainment receptors: Alabama, Arkansas, Illinois, Indiana, Kansas, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Virginia, and West Virginia. Based on the maximum downwind contributions in Table V.D–1, the following states contribute at or above the 0.75 ppb threshold to downwind maintenance-only receptors: Arkansas, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. In the proposed rule North Carolina was linked to a maintenance receptor in Baltimore Co., MD (site 240053001). North Carolina was not linked to any other receptor in the proposal. In the final rule modeling, this site is no longer projected to be a receptor because the 2017 average and maximum design values for this site are projected to be below the level of the NAAQS, and North Carolina is not linked to any other

[125] Contributions from anthropogenic emissions under ''NO_X-limited'' and ''VOC-limited'' chemical regimes were combined to obtain the net contribution from NO_X and VOC anthropogenic emissions in each state.

[126] As discussed in section IV, the EPA's assessment shows that there are problem receptors in the West where western states contribute amounts greater than or equal to the screening threshold used to evaluate eastern states (*i.e.,* 1 percent of the NAAQS), but for a number of reasons the EPA is not addressing transport in the West in this rulemaking.

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nonattainment or maintenance receptor, based on the final rule modeling.

Comment: The EPA received comments that the version of CAMx used for the proposal modeling (CAMx v6.11) did not include the most recent halogen chemistry that would affect ozone concentrations in saltwater marine atmospheres and transport of ozone from Florida to receptors in Texas. The commenter said that the EPA should include this chemistry in modeling for the final rule.

Response: In the EPA's 2017 modeling for the final rule, Florida is modeled to have an average contribution at the 0.75 ppb threshold to the 2017 design values at two receptors in Houston (*i.e.,* Harris County sites 482010024 and 482011034). A report by the CAMx model developer on the impact of modeling with the latest CAMx halogen chemistry indicates that the updated chemistry results in lower modeled ozone in air transported over saltwater marine environments for multiple days. Specifically, the report notes that on days with multi-day transport across the Gulf of Mexico, modeling with the updated chemistry could lower 8-hour daily maximum ozone concentrations by up to 2 to 4 ppb in locations in eastern Texas, including Houston. Air parcel trajectories for individual days used in the EPA's calculation of the contribution from Florida to the Houston receptors confirm that on days with high modeled transport from Florida to the receptors in Houston, air travels for multiple days over the Gulf of Mexico from Florida before reaching the receptors in Houston (see the AQM TSD for more details).

In the final rule modeling, the EPA was not able to explicitly account for the updated chemistry because this chemistry had not yet been included by the model developer in the source apportionment tool in CAMx at the time the modeling was performed for this rule. However, because Florida's maximum contribution to receptors in Houston is exactly at the 0.75 ppb threshold, the agency believes that if it had performed the final rule modeling with the updated halogen chemistry, Florida's contribution would likely be below this threshold. Therefore, the EPA is not including Florida in the final rule because it finds that Florida's contribution to downwind nonattainment and maintenance receptors is insignificant when this updated halogen chemistry is considered. As described in the AQM TSD, the source-receptor transport pattern between Florida and Houston involving multi-day transport over the Gulf of Mexico is unique such that modeling with the updated halogen chemistry would not be expected to affect linkages from other upwind states to receptors in Houston or any other linkages from upwind states to downwind nonattainment and maintenance receptors for this final rule.

Based on the EPA's application of the 0.75 ppb threshold, the linkages between each upwind state and downwind nonattainment receptors and maintenance-only receptors in the eastern U.S. are provided in Table V.E–2 and Table V.E–3, respectively.

TABLE V.E–2—LINKAGES BETWEEN EACH UPWIND STATE AND DOWNWIND NONATTAINMENT RECEPTORS IN THE EASTERN U.S.

Upwind state	Downwind nonattainment receptors
AL	Tarrant Co, TX (484392003); Tarrant Co, TX (484393009).
AR	Brazoria Co, TX (480391004).
IL	Brazoria Co, TX (480391004); Sheboygan Co, WI (551170006).
IN	Fairfield Co, CT (090019003); Sheboygan Co, WI (551170006).
KS	Tarrant Co, TX (484392003); Sheboygan Co, WI (551170006).
LA	Brazoria Co, TX (480391004); Tarrant Co, TX (484392003); Tarrant Co, TX (484393009); Sheboygan Co, WI (551170006).
MD	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
MI	Fairfield Co, CT (090019003); Sheboygan Co, WI (551170006).
MS	Brazoria Co, TX (480391004).
MO	Brazoria Co, TX (480391004); Sheboygan Co, WI (551170006).
NJ	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
NY	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
OH	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
OK	Tarrant Co, TX (484392003); Tarrant Co, TX (484393009); Sheboygan Co, WI (551170006).
PA	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
TX	Sheboygan Co, WI (551170006).
VA	Fairfield Co, CT (090019003); New Haven Co, CT (090099002).
WV	Fairfield Co, CT (090019003).

TABLE V.E–3—LINKAGES BETWEEN EACH UPWIND STATES AND DOWNWIND MAINTENANCE-ONLY RECEPTORS IN THE EASTERN U.S.

Upwind state	Downwind maintenance receptors
AR	Allegan Co, MI (260050003); Harris Co, TX (482011039).
DE	Philadelphia Co, PA (421010024).
DC	Harford Co, MD (240251001).
IL	Jefferson Co, KY (211110067); Harford Co, MD (240251001); Allegan Co, MI (260050003); Suffolk Co, NY (361030002); Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024); Harris Co, TX (482011039).
IN	Fairfield Co, CT (090013007); Jefferson Co, KY (211110067); Harford Co, MD (240251001); Allegan Co, MI (260050003); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024).
IA	Allegan Co, MI (260050003).
KS	Allegan Co, MI (260050003).
KY	Harford Co, MD (240251001); Richmond Co, NY (360850067); Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024).
LA	Denton Co, TX (481210034); Harris Co, TX (482010024); Harris Co, TX (482011034); Harris Co, TX (482011039).

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TABLE V.E–3—LINKAGES BETWEEN EACH UPWIND STATES AND DOWNWIND MAINTENANCE-ONLY RECEPTORS—Continued IN THE EASTERN U.S.

Upwind state	Downwind maintenance receptors
MD	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Philadelphia Co, PA (421010024).
MI	Fairfield Co, CT (090013007); Jefferson Co, KY (211110067); Harford Co, MD (240251001); Suffolk Co, NY (361030002); Hamilton Co, OH (390610006).
MS	Harris Co, TX (482011039).
MO	Allegan Co, MI (260050003); Hamilton Co, OH (390610006); Harris Co, TX (482011034); Harris Co, TX (482011039).
NJ	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Philadelphia Co, PA (421010024).
NY	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007).
OH	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Jefferson Co, KY (211110067); Harford Co, MD (240251001); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Philadelphia Co, PA (421010024).
OK	Allegan Co, MI (260050003); Denton Co, TX (481210034); Harris Co, TX (482011034); Harris Co, TX (482011039).
PA	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Harford Co, MD (240251001); Richmond Co, NY (360850067); Suffolk Co, NY (361030002).
TN	Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024).
TX	Harford Co, MD (240251001); Allegan Co, MI (260050003); Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024).
VA	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Harford Co, MD (240251001); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Philadelphia Co, PA (421010024).
WV	Fairfield Co, CT (090010017); Fairfield Co, CT (090013007); Harford Co, MD (240251001); Richmond Co, NY (360850067); Suffolk Co, NY (361030002); Hamilton Co, OH (390610006); Philadelphia Co, PA (421010024).
WI	Allegan Co, MI (260050003).

The EPA's modeling to quantify upwind state EGU NO_X emission budgets, described in section VI, used a more recent IPM version 5.15 base case projection as compared to the IPM projection used for air quality modeling described here in section V. This more recent IPM base case reflects minor updates to IPM model inputs. Because this more recent IPM base case projection was not used for the air quality modeling for the final rule, the aforementioned results do not account for updates which are subsequently included in the budget-setting analysis. In order to ensure that the budget-setting base case projection would not change any conclusions drawn from the air quality modeling, the EPA performed an assessment of the budget-setting base case using a method that relied on the EPA's air quality modeling contribution data as well as projected ozone concentrations from the EPA's 2017 illustrative policy case developed for the Regulatory Impact Analysis. For more information about these methods, refer to the Ozone Transport Policy Analysis Final Rule TSD. This assessment shows no change in the set of nonattainment or maintenance receptors identified here in section V. In addition to evaluating the status of downwind receptors identified for the rule, the EPA evaluated whether the budget-setting base case would reduce ozone contributions from upwind states to the extent that a previously linked state would have a maximum contribution less than the one percent threshold. This assessment shows that with the budget-setting base case, all previously identified states are expected to remain linked (*i.e.,* contribute greater than or equal to one percent of the NAAQS) to at least one downwind nonattainment or maintenance receptor. Therefore, using the budget-setting base case for the final rule does not impact the scope of states linked to downwind nonattainment or maintenance receptors relative to the modeled base case.

Additionally, after the emissions and air quality modeling for the final rule were already underway, Pennsylvania published a new RACT rule [127] that would require EGU and non-EGU NO_X reductions starting on January 1, 2017. The EPA recognizes that the implementation of this final state rule will precede the first control period for the final CSAPR Update rule. The agency believes it is reasonable to evaluate the potential influence of the Pennsylvania RACT rule on downwind receptors and state linkages identified for this final rule prior to evaluating any further EGU NO_X reductions for the CSAPR Update rule. Therefore, because Pennsylvania's new RACT rule was not represented explicitly in the emission inventory and air quality modeling already underway, the EPA first added an evaluation of emissions and air quality impacts expected to result from Pennsylvania's RACT rule [128] before then evaluating air quality impacts of the further reductions that might be required under the CSAPR Update rule at each uniform control stringency identified. The EPA estimates that, for the adjusted historical emission level including Pennsylvania RACT, no nonattainment or maintenance receptors identified in section V dropped below 76 ppb and Pennsylvania's contribution to downwind ozone problems did not drop below one percent of the NAAQS. Therefore, the identified receptors and linked upwind states in section V remain unchanged.

VI. Quantifying Upwind State EGU NO_X Emission Budgets To Reduce Interstate Ozone Transport for the 2008 NAAQS

A. Introduction

This section describes the EPA's methodology for quantifying emission budgets to reduce interstate emission transport for the 2008 ozone NAAQS. The CSAPR Update emission budgets limit allowable emissions and represent the emission levels that remain after each state makes EGU NO_X emission reductions that are necessary to reduce interstate ozone transport for the 2008 NAAQS. The EPA's assessment of upwind state emission budgets in this rule reflects analysis of uniform NO_X

[127] Published April 23, 2017 (*http://www.pabulletin.com/secure/data/vol46/46-17/694.html*).

[128] For more information about the EPA's assessment of Pennsylvania's RACT rule, see the Pennsylvania RACT memo to the docket for this rulemaking.

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emission control stringency. Each level of uniform NO_X control stringency represents an estimated marginal cost per ton of NO_X reduced and is characterized by a set of pollution control measures. The EPA applies a multi-factor test, the same multi-factor test that was used in the original CSAPR,[129] to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test considers cost, available emission reductions, and downwind air quality impacts to determine the appropriate level of uniform NO_X control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. The uniform NO_X emission control stringency, represented by marginal cost, also serves to apportion the reduction responsibility among collectively-contributing upwind states. This approach to quantifying upwind state emission reduction obligations using uniform cost was reviewed by the Supreme Court in *EPA* v. *EME Homer City Generation,* which held that using such an approach to apportion emission reduction responsibilities among upwind states that are collectively responsible for downwind air quality impacts ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 134 S. Ct. at 1607.

There are four stages in developing the multi-factor test to quantify upwind state emission budgets as to the 2008 ozone NAAQS: (1) Identify levels of uniform NO_X control stringency (represented by an estimated marginal cost of control that is applied across linked upwind states); (2) evaluate NO_X emission reductions and corresponding NO_X emission budgets (*i.e.,* remaining allowable emissions after reductions are made) at each identified level of uniform control stringency; (3) assess air quality improvements resulting at each level of control; and (4) select a level of control stringency by applying the multi-factor test to consider cost, available emission reductions, and downwind air quality impacts, including ensuring that the budgets do not unnecessarily over-control relative to the contribution threshold or downwind air quality.

The multi-factor evaluation informs the EPA's determination of appropriate EGU NO_X ozone season emission budgets necessary to reduce emissions that significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS for the 2017 ozone season and subsequent control periods. For most CSAPR Update states, the emission reductions achieved through implementation of these budgets will partially satisfy the EPA's good neighbor FIP obligation to fully prohibit emissions that contribute to downwind air quality problems with respect to the 2008 ozone NAAQS pursuant to CAA section 110 (a)(2)(D)(i)(I).[130] For one state, Tennessee, the emission reductions achieved through implementation of its emission budget will fully satisfy the EPA's good neighbor FIP obligation for the 2008 ozone NAAQS. Section VII describes the EPA's approach to implementing these emission budgets through updates to the CSAPR NO_X ozone season trading program.

B. Levels of Uniform Control Stringency

The following subsections describe the EPA's analysis to establish levels of uniform control stringency for EGU and non-EGU point sources. Each level of uniform NO_X control stringency is characterized by a set of pollution control measures and represents an estimated marginal cost per ton of NO_X reduced. This section summarizes the EPA's findings when assessing NO_X reduction strategies and cost.

As described in section IV of this preamble, the EPA is quantifying near-term ozone season NO_X emission reductions to reduce interstate emission transport for the 2008 ozone NAAQS in order to assist downwind states with meeting the impending July 20, 2018 Moderate area attainment date. Although this final rule does not require or impose any specific technology standards on affected sources, the EPA limited its analysis of potential NO_X reductions in each upwind state to those that could be feasibly implemented for the 2017 ozone season, which is the last full ozone season prior to the July 20, 2018 attainment date. This approach ensures that the emission budgets are achievable for the 2017 ozone season. The EPA did not further analyze potential NO_X reductions from strategies that were deemed infeasible to implement for the 2017 ozone season for purposes of quantifying upwind state emission budgets, but the EPA anticipates considering those controls in any future action that may be necessary to address upwind states' full emission reduction obligations with respect to the 2008 ozone standard. For more details on these assessments, refer to the EGU NO_X Mitigation Strategies Final Rule TSD and the Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance Final Rule TSD in the docket for this rule.

1. EGU NO_X Mitigation Strategies

In developing levels of uniform control stringency, the EPA considered all NO_X control strategies that are widely in use by EGUs: Fully operating existing Selective Catalytic Reduction (SCR), including both optimizing NO_X removal by existing, operational SCRs and turning on and optimizing existing idled SCRs; turning on existing idled SNCRs; installing state-of-the-art NO_X combustion controls; shifting generation to existing units with lower-NO_X emission rates within the same state; and installing new SCRs and SNCRs. For the reasons explained in the EGU NO_X Mitigation Strategies Final Rule TSD, the EPA determined that these EGU NO_X mitigation strategies are feasible for the 2017 ozone season, with the exception of installing new SCRs or SNCRs.

The following subsections describe the EPA's identification of uniform levels of NO_X emission control stringency. Each level of uniform NO_X control stringency represents an estimated marginal cost per ton of NO_X reduced and is characterized by a set of pollution control measures. The levels of NO_X control stringency identified are used in the EPA's multi-factor test described later on.

a. *$800 per ton, representing optimizing existing and operating SCRs.* Optimizing NO_X removal for existing and operating SCRs can significantly reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. SCRs can achieve up to 90 percent reduction in EGU NO_X with sufficient reagent and installed catalyst. These controls are in widespread use across the U.S. power sector. In the 22 state CSAPR Update region, approximately 53 percent of coal-fired EGU capacity and 76 percent of natural gas combined cycle (NGCC) EGU capacity is equipped with SCR. Recent power sector data reveal that some SCR controls are being underused. In some cases, SCR controls are not fully operating (*i.e.,* the controls could be operated at a greater NO_X removal rate).[131] As described later on in this preamble, the EPA finds that optimizing existing and operating SCRs is a readily

[129] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

[130] See section IV.B.4 for further discussion of this partial remedy.

[131] This assessment is available in the EGU NO_X Mitigation Strategies Final Rule TSD.

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available approach for EGUs to reduce NO_X emissions.

The EPA identifies $800 per ton as a level of uniform control stringency that represents optimizing existing SCR controls that are already operating to some extent. The EPA's final analysis for the CSAPR Update rule is informed by comment on the proposal.[132] This cost level is premised on variable costs, specifically additional reagent (*i.e.,* ammonia or urea) and additional catalyst, being the primary costs incurred for optimizing an existing SCR unit that is already operating to some extent. More information about this analysis is available in the EGU NO_X Mitigation Strategies Final Rule TSD.

b. *$1,400 per ton, representing turning on idled existing SCRs and installing state-of-the-art NO_X combustion controls*.

Turning on idled, existing SCRs also can significantly reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. Recent power sector data reveal that, in some cases, SCR controls have been idled for several seasons or years. The EPA finds that turning on idled SCRs is a readily available approach for EGUs to reduce NO_X emissions.

The EPA identifies $1,400 per ton as a level of uniform control stringency that represents turning on idled SCR controls. The EPA's analysis of this level of uniform control stringency for the final CSAPR Update is informed by comment on the proposal.[133] While the costs of optimizing existing, operational SCRs include only variable costs (as described earlier), the cost of bringing existing SCR units that are currently idled back into service considers both variable and fixed costs. Variable and fixed costs include labor, maintenance and repair, reagent, parasitic load, and ammonia or urea. The EPA performed an in-depth cost assessment for all coal-fired units with SCRs. More information about this analysis is available in the EGU NO_X Mitigation Strategies Final Rule TSD, which is found in the docket for this rule.

The EPA also includes installing state-of-the-art combustion controls in the level of uniform control stringency represented by $1,400 per ton. State-of-the-art combustion controls such as low-NO_X burners (LNB) and over-fire air (OFA) can be installed quickly, and can significantly reduce EGU NO_X emissions. In the 22 state CSAPR Update Region, approximately 99 percent of coal-fired EGU capacity in the East is equipped with some form of combustion control. Combustion controls alone can achieve NO_X emission rates of 0.15 to 0.50 lbs/mmBtu.[134] Once installed, combustion controls reduce NO_X emissions at all times of EGU operation. The EPA finds that the installation of state-of-the-art combustion controls is a readily available approach for EGUs to reduce NO_X emissions.

The cost of installing state-of-the-art combustion controls per ton of NO_X reduced is dependent on the combustion control type and unit type. The EPA estimates the cost per ton of state-of-the-art combustion controls to be $500 per ton to $1,200 per ton of NO_X removed. In specifying a representative marginal cost at which state-of-the-art combustion controls are widely available, the EPA uses the conservatively high end of this identified range of costs, $1,200 per ton. Because $1,200 per ton is similar in terms of EGU NO_X control stringency to $1,400 per ton, for purposes of the analysis that follows, the EPA includes installing state-of-the-art NO_X combustion controls in the uniform control stringency level represented by $1,400 per ton of NO_X removed.[135]

c. *$3,400 per ton, representing turning on idled existing SNCRs.* Turning on idled existing SNCRs can also significantly reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. SNCRs can achieve up to 25 percent reduction in EGU NO_X emissions (with sufficient reagent). These controls are in widespread use across the U.S. power sector. In the 22 state CSAPR Update region, approximately 10 percent of coal-fired EGU capacity is equipped with SNCR. Recent power sector data reveal that, in some cases, SNCR controls have been idled for several seasons or years. The EPA finds that turning on idled SNCRs is a readily available approach for EGUs to reduce NO_X emissions

The EPA identifies $3,400 per ton as a level of uniform control stringency that represents turning on and fully operating idled SNCRs. For existing SNCRs that have been idled, unit operators may need to restart payment of some fixed and variable costs associated with these controls. Fixed and variable costs include labor, maintenance and repair, reagent, parasitic load, and ammonia or urea. The majority of the total fixed and variable operating costs for SNCR is related to the cost of the reagent used (*e.g.,* ammonia or urea) and the resulting cost per ton of NO_X reduction is sensitive to the NO_X rate of the unit prior to SNCR operation. For more details on this assessment, refer to the EGU NO_X Mitigation Strategies Final Rule TSD in the docket for this rule.

d. $5,000 per ton, representing installing new SCRs. The amount of time to retrofit with new SCR exceeds the implementation timeframes considered in this final rule. It would therefore not be feasible to retrofit new SCR to achieve EGU NO_X reductions for the 2017, or even 2018, ozone season. Exclusion of new SCR installation from this analysis reflects a determination only that these strategies are infeasible for implementation of this rule, not a determination that they are infeasible or inappropriate for consideration of NO_X reduction potential to address interstate emission transport over a longer timeframe. *See* EGU NO_X Mitigation Strategies Final Rule TSD for discussion of feasibility of EGU NO_X controls for the 2017 ozone season.

The EPA identifies $5,000 per ton as a level of uniform control stringency that represents retrofitting a unit with new SCR technology. The EPA evaluated this level of uniform NO_X emission control stringency, with the limitation that no new SCR systems were installed as a result of the EPA's analysis for the 2017 ozone season. The agency examined the cost for retrofitting a unit with new SCR technology, which typically attains controlled NO_X rates of 0.07 lbs/mmBtu, or less. Because this EGU NO_X reduction strategy is prospective and the EPA does not know the exact specifications of EGUs that may find this NO_X reduction strategy feasible and cost-effective beyond 2017, it performed a cost analysis using a representative electric generating unit.

[132] The EPA proposed that $500 per ton was a level of uniform control stringency that represented optimizing existing SCR controls that are already operating to some extent. The EPA received comments suggesting that its cost estimates should be revised. Details of the EPA's final cost analysis can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

[133] The EPA proposed that $1,300 per ton was a level of uniform control stringency that represented turning on idled SCR controls. The EPA received comments suggesting that its cost estimates should be revised. Details of the EPA's final cost analysis can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

[134] Details of the EPA's assessment of state-of-the-art NO_X combustion controls are provided in the EGU NO_X Mitigation Strategies Final Rule TSD.

[135] As described in section VI, the EPA's assessment of emission budgets reflecting uniform NO_X control stringency represented by $1,400 per ton does not over-control as to any upwind state. Only one state, Tennessee, fully resolves its obligation at this level of control stringency and Tennessee's emission budget is exactly the same at $800 per ton and $1,400 per ton, indicating that it was not necessary for the agency to evaluate a distinct level of uniform NO_X control stringency linked solely installing state-of-the-art NO_X combustion controls.

A coal-fired EGU with an uncontrolled NO_X rate of 0.35 lbs/mmBtu, retrofitted with an SCR to a lower emission rate of 0.07 lbs/mmBtu, results in a cost of approximately $5,000 per ton of NO_X removed. For more details on this assessment, refer to the EGU NO_X Mitigation Strategies Final Rule TSD in the docket for this rule.

e. *$6,400 per ton, representing installing new SNCRs.* The amount of time to retrofit with new SNCR exceeds the implementation timeframes considered in this final rule. It would therefore not be feasible to retrofit new SNCR to achieve EGU NO_X reductions for the 2017, or even 2018, ozone season. Exclusion of new SNCR installation from this analysis reflects a determination only that these strategies are infeasible for implementation of this rule, not a determination that they are infeasible or inappropriate for consideration of NO_X reduction potential to address interstate emission transport over a longer timeframe. *See* EGU NO_X Mitigation Strategies Final Rule TSD for discussion of feasibility of EGU NO_X controls for the 2017 ozone season.

The EPA identifies $6,400 per ton as a level of uniform control stringency that represents retrofitting a unit with new SNCR technology. The EPA evaluated this level of uniform NO_X emission control stringency, with the limitation that no new SNCR systems were installed as a result of the EPA's analysis for the 2017 ozone season. SNCR technology provides owners a low capital cost option for reducing NO_X emissions, albeit at the expense of higher operating costs. The higher cost per ton of NO_X removed reflects this technology's lower removal efficiency, which results in greater reagent consumption and escalates the cost of operating the SNCR relative to tons of NO_X removed. Owners may favor this technology to meet certain NO_X performance requirements for certain units. Because this EGU NO_X reduction strategy is prospective and the EPA does not know the exact specifications of EGUs that may find this NO_X reduction strategy feasible and cost-effective beyond 2017, the EPA performed a cost analysis using a representative electric generating unit. For a unit with a 40 percent capacity factor and using a NO_X emission reduction assumption of 25 percent, the cost is $6,500 per ton of NO_X removed. For more details on this assessment, refer to the EGU NO_X Mitigation Strategies Final Rule TSD in the docket for this rule.

2. Non-EGU NO_X Mitigation Strategies and Feasibility for the 2017 Ozone Season

The EPA is not at this time addressing non-EGU emission reductions in its efforts to reduce interstate emission transport for the 2017 ozone season with respect to the 2008 ozone NAAQS. As compared to EGUs, there is greater uncertainty in the EPA's current assessment of non-EGU point-source NO_X mitigation potential and the EPA believes more time is required for states and the EPA to improve non-EGU point source data and pollution control assumptions before including related reduction potential in this regulation. Further, the 2017 ozone season implementation timeframe for this rulemaking would limit the number of non-EGU source categories that could potentially implement NO_X emission reductions within that timeframe. Finally, using the best information available to the EPA, which was submitted for public comment with the proposed CSAPR Update, the EPA finds that there are more non-EGU point sources than EGU sources and that these sources on average emit less relative to EGUs. The implication of these fleet characteristics is that there are more individual sources to control and there are relatively fewer emission reductions available from each source. Considering these factors, the EPA finds substantial uncertainty regarding whether significant aggregate NO_X mitigation is achievable from non-EGU point sources for the 2017 ozone season.

In assessing the potentially available 2017 ozone season NO_X emission reductions from non-EGU sources, the EPA identified potential controls, the reduction potential of each control, the associated cost of each control using a nationwide average, and the timing for the installation of control. The EPA then evaluated the cost-effective controls that could be implemented by the 2017 ozone season. While there may be a few categories where cost-effective installation of non-EGU NO_X controls on a limited number of sources would be feasible by the 2017 ozone season, the EPA does not observe that significant, certain, and meaningful non-EGU NO_X reduction is in fact feasible for the 2017 ozone season. For example, one factor influencing uncertainty is that the EPA lacks sufficient information on the capacity and experience of suppliers and major engineering firms' supply chains to conclude that they would be able to execute the project work for non-EGU sources in the limited timeframe of this rule.

The EPA has evaluated the potential for ozone season NO_X reductions from non-EGU sources. A detailed discussion of this assessment was provided in the draft Non-EGU NO_X Mitigation Potential TSD, which was located in the docket for the proposed rule and was available for comment. The EPA did not receive any comments that changed its conclusions in the draft Non-EGU NO_X Mitigation Potential TSD. As commenters generally agreed with the EPA's assessment with respect to the regulation of non-EGUs in this rule, the TSD will be finalized with no substantive change from the proposal TSD. This TSD contains information shared at the proposal on non-EGU source category emissions, the EPA's tools for estimating emission reductions from non-EGU categories, brief discussions of available controls, costs, potential emission reductions for specific source categories and efforts, to date, to review and refine its estimates for certain states. There were no significant comments on the TSD, and the minor comments that were received will be addressed in the response to comments document. The EPA views this non-EGU assessment as a step toward future efforts to evaluate non-EGU categories that may be necessary to fully quantify upwind states' significant contribution to nonattainment or interference with maintenance.

Although the EPA is not analyzing non-EGU reductions for purposes of quantifying emission budgets in this final action, future EPA rulemakings or guidance could revisit the potential for reductions from non-EGU sources.

3. Summary of EGU Uniform Control Stringency Represented by Marginal Cost of Reduction (Dollar per Ton)

Table VI.B–1 lists the final EGU uniform NO_X emission control stringencies, represented by marginal cost per ton of NO_X reduced, that the EPA evaluated and the NO_X reduction strategy or policy that identified each uniform cost level.

TABLE VI.B–1—LEVELS OF EGU UNIFORM NO_X EMISSION CONTROL STRINGENCY AND REPRESENTATIVE MARGINAL COST

Levels of EGU uniform control stringency	Representative EGU NO_X controls
$800 per ton	Widespread availability of optimizing existing and operating SCRs.
$1,400 per ton	Widespread availability of turning on idled existing SCRs and installing state-of-the-art combustion controls.
$3,400 per ton [136]	Widespread availability of turning on idled existing SNCRs.
$5,000 per ton	Widespread availability of installing new SCRs.[137]
$6,400 per ton	Widespread availability of installing new SNCRs.[138]

The EPA finds that $800 per ton is the lowest marginal cost at which any specific EGU pollution control technology (*i.e.,* optimizing existing and operating SCRs) is available and feasible in the timeframe for implementing this rule. The EPA's final analysis shows that no specific EGU NO_X reduction technologies are available at a lower cost than $800 per ton. The implication of this finding is that evaluating $500 per ton, which was assessed at proposal, for the final rule would not yield any EGU NO_X reduction potential attributable to specific pollution control technologies. As such, $800 per ton is the lowest uniform cost evaluated for the final CSAPR Update.

In the CSAPR Update proposal, the EPA also evaluated $10,000 per ton as a uniform level of control stringency. The EPA identified this level of control stringency as an upper bound for the analysis conducted for the proposed rule. However, the proposal's analysis showed that no specific EGU NO_X reduction technologies were available at a higher cost than $6,400 per ton. The EPA did not receive comment on the proposal indicating that there are additional EGU NO_X reduction technologies available between $6,400 per ton and $10,000 per ton. As a result, the EPA did not evaluate $10,000 per ton as a uniform level of control stringency for the final CSAPR Update.

The EPA finds that the selection of uniform cost thresholds presented in Table VI.B–1 is appropriate to evaluate potential EGU NO_X reductions and corresponding emission budgets to address interstate emission transport for the 2008 ozone NAAQS. The EPA has identified cost thresholds where control technologies are widely available and therefore where the most significant incremental emission reduction potential is expected. The EPA did not evaluate additional cost thresholds in between those selected because this analysis would not yield meaningful insights as to NO_X reduction potential as the EPA did not identify any control technologies that become available at such cost thresholds. Because these cost thresholds are linked to costs at which EGU NO_X mitigation strategies become widely available in each state, the cost thresholds represent the break points at which the most significant step-changes in EGU NO_X mitigation are expected.

C. EGU NO_X Reductions and Corresponding Emission Budgets

The EPA evaluated the EGU NO_X reduction potential for each identified uniform level of NO_X control stringency represented by marginal cost. This analysis applied the uniform control stringency to EGUs in each upwind state NO_X using IPM version 5.15. The EPA then used the modeled EGU NO_X reduction potential in combination with monitored EGU data to quantify emission budgets for each uniform level of NO_X control stringency. The next step of the process (described in the next subsection) evaluated air quality impacts of each set of emission budgets.

1. Evaluating EGU NO_X Reduction Potential

The EPA evaluates emission reductions from all EGU NO_X mitigation strategies available at each level of uniform NO_X control stringency. However, two components of this assessment are key to the level of reductions available and/or received significant comment at proposal. These components are the achievable NO_X rate for units with SCR and shifting generation to lower NO_X-emitting or zero-emitting EGUs.

One key input to the EPA's analysis of EGU NO_X reduction potential is the NO_X emission rate that can be achieved for EGUs with SCRs that are not optimized or are idled. This input influences the EPA's estimate of EGU NO_X reduction potential and corresponding NO_X ozone season emission budgets. To estimate EGU NO_X reduction potential from optimizing or turning-on idled SCRs, the EPA considers the delta between the non-optimized or idled NO_X emission rates and an achievable operating and optimized SCR NO_X emission rate. Assuming a higher achievable EGU NO_X emission rate for SCRs yields a higher emission budget and assuming a lower achievable EGU NO_X emission rate for SCRs yields a lower emission budget. For the final rule analysis, the EPA finds that an achievable 2017 EGU NO_X ozone season emission rate for units with SCR is 0.10 lbs/mmBtu. To determine this rate, the EPA evaluated coal-fired EGU NO_X ozone season emission data from 2009 through 2015 and calculated an average NO_X ozone season emission rate across the fleet of coal-fired EGUs with SCR for each of these seven years. The EPA finds it prudent to not consider the lowest or second lowest ozone season NO_X rates, which may reflect new SCR systems that have all new components (*e.g.,* new layers of catalyst). Data from these new systems are not representative of ongoing achievable NO_X rates considering broken-in components and routine maintenance schedules. The EPA believes that the third lowest fleet-wide average coal-fired EGU NO_X rate for EGUs with SCR is representative of ongoing achievable emission rates. The EPA observes that the third lowest fleet-wide average coal-fired EGU NO_X rate for EGUs with SCR is 0.10 lbs/mmBtu. The EPA has implemented 0.10 lbs/mmBtu as an EGU NO_X rate ceiling in IPM. For more information about how this rate is implemented in IPM, see the EPA's IPM documentation, which can be found in the docket for this rulemaking or at *www.epa.gov/powersectormodeling*.

The EPA's analysis of SCR NO_X rates for the final rule differs from the proposal in two ways. First, the evaluation focuses on a more recent timeframe for analysis—2009 through 2015 compared to 2003 through 2014. The EPA believes this change is reasonable because there have been

[136] The EPA notes that this cost is similar to the NO_X SIP Call ozone season NO_X cost threshold, adjusted to 2014$.

[137] The cost assessment for new SCR is available in the EGU NO_X Mitigation Strategies Final Rule TSD. While chosen to define a cost-threshold, new SCRs were not considered a feasible control on the compliance timeframe for this rule.

[138] The cost assessment for new SNCR is available in the EGU NO_X Mitigation Strategies Final Rule TSD. While chosen to define a cost-threshold, new SNCRs were not considered a feasible control on the compliance timeframe for this rule.

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significant shifts in the power sector since 2003, particularly with respect to power sector economics (*e.g.,* lower natural gas prices in response to shale gas development) and environmental regulations (*e.g.,* CAIR and CSAPR). Because of these changes, the EPA considers it reasonable to evaluate SCR performance focusing on more recent historical data that better represent the current landscape of considerations affecting the power sector. The EPA chose 2009 because that is the first year of CAIR NO_X annual compliance. Second, the analysis focuses on the third best ozone season average rate as compared to the second best rate at proposal. The EPA believes that the second best rate, as discussed previously, could continue to capture disproportionately new SCR components and does not necessarily reflect achievable ongoing NO_X emission rates. Therefore, the EPA is finalizing analysis using the third best rate.

The proposed CSAPR Update put forward 0.075 lbs/mmBtu as a widely achievable EGU NO_X ozone season emission rate for coal-fired EGUs with SCR. As noted in the previous paragraph, the EPA has reassessed this assumption, partly in response to comment received on the proposal. Some of the key comments are summarized later and additional detail can be found in the Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance Final TSD and the Response to Comments Document.

Comment: Some commenters suggested that the EPA's proposed coal-fired EGU NO_X ozone season emission rate of 0.075 lbs/mmBtu for units with SCR was too low and did not represent an achievable NO_X rate for the 2017 ozone season. These commenters provided several examples of changes in power sector economics that have significantly changed EGU dispatch in recent years and also changes in compliance planning for environmental regulations. These commenters suggested that the EPA should consider a shorter time-frame for evaluating SCR operation.

Response: The EPA acknowledges that various factors, both economic and regulatory, have influenced the power sector in recent years. The EPA believes that the achievable SCR NO_X rate and underlying assumptions that it is finalizing in this action are generally responsive to these comments. As discussed previously, for the purposes of evaluating EGU NO_X reduction potential, the EPA uses an EGU NO_X emission rate for units with SCR of 0.10 lbs/mmBtu as a ceiling in the IPM model. This rate reflects a generally achievable NO_X emission rate that is appropriate for the EPA's budget-setting purposes. The use of this rate to establish emission budgets was supported in comments by many power sector companies and their representative groups.

Comment: Other commenters noted that many coal-fired EGUs with SCR have demonstrated the ability to achieve NO_X emission rates of 0.06 lbs/mmBtu or lower. These commenters suggested that the EPA should use SCR NO_X ozone season emission rates that are lower than 0.075 lbs/mmBtu in quantifying emission budgets.

Response: The EPA acknowledges that many individual coal-fired EGUs with SCR have achieved rates lower than 0.075 lbs/mmBtu. However, in evaluating a regional environmental challenge (*i.e.,* interstate transport of ozone pollution) and designing an analysis of EGU NO_X reduction potential in the many states in that region, the EPA believes it is prudent to consider a range of demonstrated NO_X emission rates and believes that an ozone season average is a more reasonable approach for identifying NO_X reduction potential using a uniform standard.

Another key input to the EPA's analysis of EGU NO_X reduction potential is shifting generation to existing, lower NO_X-emitting or zero-emitting EGUs within the same state. Shifting generation to existing lower NO_X-emitting or zero-emitting EGUs within the same state would be a readily available approach for EGUs to reduce NO_X emissions, and the EPA included this NO_X mitigation strategy in quantifying EGU NO_X reduction potential in the analyses informing this rule.

Regarding feasibility of shifting generation to existing lower-NO_X emitting or zero-emitting units within the same state for the 2017 ozone season, the EPA finds that this EGU NO_X reduction strategy is consistent with demonstrated EGU dispatch behavior. Power generators produce a relatively fungible product, electricity, and they operate within an interconnected electricity grid in which electricity generally cannot be stored in large volumes, so generation and use must be balanced in real time. *See FERC* v. *Elec. Power Supply Ass'n,* 136 S. Ct. 760, 768 (2016). Because of their uniquely interconnected and interdependent operations—so much so that the utility sector has been likened to a ''complex machine'' [139]—power plants shift generation in the normal course of business. Every time a power plant either increases or decreases operations, that has implications for the overall amount of pollution emitted by other plants within the interconnected electricity grid, because those other plants must commensurately decrease or increase their operations to balance supply with demand. As a result, by shifting some generation from higher-emitting to lower-emitting plants, sources can achieve an effective degree of emission limitation that might otherwise have required them to make much more expensive investments in end-of-stack technologies at their particular plants. As a result, sources would likely use shifting generation measures to comply with standards whenever doing so is less expensive than end-of-stack controls, even if EPA considered only end-of-stack controls in determining those standards. Further, the flexibility that power plants have to shift generation in establishing dispatch patterns is synergistic with the flexibility afforded by implementation through an allowance trading program, as the EPA is finalizing in this CSAPR Update. Allowance prices can be seamlessly factored into dispatch decisions, which provides for an efficient approach to administering shifting generation for compliance with the CSAPR Update requirements, if EGUs so choose. For these reasons, it is therefore reasonable for the EPA to consider that sources may cost-effectively address their emissions through arrangements that incorporate cleaner forms of power generation.

For establishing emission budgets for the CSAPR Update, the EPA finds that shifting specified, small amounts of generation to existing lower NO_X-emitting or zero-emitting units could occur consistent with the near-term 2017 implementation timing for this rule.[140] As a proxy for limiting the amount of generation shifting that is feasible for the 2017 ozone season, the EPA limited its assessment to shifting generation to other EGUs within the same state. The EPA believes that limiting its evaluation of shifting generation (which we sometimes refer to as re-dispatch) to the amount that could

[139] Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007). The integrated nature of the utility power sector is well-recognized. *See, e.g.,* CAA section 404(f)(2)(B)(iii)(I); *New York* v. *Federal Energy Regulatory Commission,* 535 U.S. 1, at 7 (2002).

[140] The EGU NO_X Mitigation Strategies Final Rule TSD provides data indicating the extent to which electricity generation shifted from one ozone season to another in recent years.

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occur within the state transfer represents a conservatively small amount of generation-shifting because it does not capture further potential emission reductions that would occur if generation was shifted more broadly among units in different states within the interconnected electricity grid, which the EPA believes is feasible over time. However, this broader, interstate generation-shifting may involve greater complexity—due to, for example, the greater amount of demand, larger number of sources, and greater amount of infrastructure involved—and therefore may be more challenging to implement in the near term. Limiting our consideration of such generation-shifting potential to a small percentage of total generation-shifting potential is consistent with the limited amount of time that states and sources have to achieve the required reductions. EPA relied on the in-state limitation as a reasonable indication of the amount of EGU NO_X reduction potential from shifting generation to existing lower NO_X-emitting or zero-emitting units that states and sources can readily implement by the 2017 summer ozone season. Of course, sources are not limited to generation-shifting within state, and instead are free to shift generation across state lines to comply with the CSAPR Update requirements.

Regarding the cost of the amount of generation-shifting that would result from shifting generation to existing lower-NO_X emitting or zero-emitting units within the same state, the EPA finds that this NO_X reduction strategy occurs on a cost continuum rather than at a discrete marginal cost per ton of NO_X. In tracking power sector development over time, the EPA observes that shifting generation to existing lower-NO_X emitting or zero-emitting EGUs occurs in response to economic factors such as fuel costs. Similar to this response to economic factors, the EGU NO_X reduction potential analysis conducted for the CSAPR Update rule shows shifting generation occurring on a continuum in response to environmental policy, represented by marginal cost of NO_X reductions. In other words, unlike the retrofit pollution control technologies that are evaluated in this CSAPR Update, there is no discrete cost at which this EGU NO_X mitigation strategy is singularly widely available. Rather, relatively lower marginal NO_X costs incentivize some EGU NO_X reductions from shifting generation, while relatively higher marginal NO_X costs incentivize more EGU NO_X reductions from shifting generation. The EPA quantified NO_X reduction potential from this EGU NO_X reduction strategy at each uniform NO_X control stringency level analyzed. As described in the EGU NO_X Mitigation Strategies Final Rule TSD, the amount of generation shifting seen in the CSAPR Update is modest in comparison to ozone season-to-ozone season generation shifting seen in recent years.

Comment: Commenters raised concerns regarding the EPA's authority pursuant to CAA section 110(a)(2)(D)(i)(I) to analyze generation shifting as a NO_X reduction strategy for purposes of calculating budgets for the final rule. The commenters cite the statutory language requiring states to prohibit ''any source . . . from emitting'' pollutants that contribute to downwind nonattainment and maintenance as constraining the EPA's authority to require reductions only from existing sources. The commenters claim that this language prohibits the EPA's authority to require sources to re-dispatch to new or alternative existing emission sources as this does not constitute a control on a ''source.'' Commenters add that the proposed budgets make it impossible for states to comply without taking this measure. Some commenters claim that, while the EPA may not set budgets assuming generation shifting, re-dispatch can serve as a compliance option for EGUs to meet budgets quantified in this rule.

Some commenters cite to the EPA's reliance on generation shifting in developing the best system of emissions reductions (BSER) pursuant to CAA section 111(d) in the CPP. These commenters claim that the EPA cannot rely on the same justification used to consider generation shifting in the CPP because, unlike CO_2, NO_X is not a global, well-mixed pollutant with limited control options. These commenters also note that the EPA's assertion that section 111(d) permits consideration of generation shifting is subject to current litigation.

Response: The good neighbor provision requires state and federal plans implementing its requirements to ''prohibit[ ] . . . *any source or other type of emissions activity within the State* from emitting any air pollutant in *amounts* which will'' significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state. CAA section 110(a)(2)(D)(i)(I) (emphasis added). The EPA's consideration of the potential for generation shifting in developing state budgets is consistent with this statutory requirement.

First, contrary to the commenters' contention, the statute does not limit the EPA's authority under the good neighbor provision to basing regulation only to control strategies for individual sources. The statute authorizes the state or EPA in promulgating a plan to prohibit emissions from ''any source or other type of emissions activity within the State'' that contributes (as determined by EPA) to the interstate transport problem with respect to a particular NAAQS. This broad statutory language shows that Congress was directing the states and the EPA to address a wide range of entities and activities that may be responsible for downwind emissions. However, this provision is silent as to the type of emission reduction measures that the states and the EPA may consider in establishing emission reduction requirements, and it does not limit those measures to individual source controls. The EPA reasonably interprets this provision to authorize consideration of a wide range of measures to reduce emissions from sources, which is consistent with the broad scope of this provision, as noted immediately above.[141] In the case of power plants, those measures can include on-site technology-based control measures, but they can also include measures through which power plants reduce emissions by shifting generation from higher-emitting EGUs to lower-emitting EGUs. It should be noted that because of the integrated nature of the power sector, higher-emitting EGUs have a variety of methods for implementing generation-shifting.[142] In addition, states can take action, such as imposing permit limits, that would result in generation shifting.

Moreover, the statute instructs the plan to prohibit emissions activity in ''amounts'' that significantly contribute to nonattainment or interfere with maintenance of downwind air quality. In identifying those amounts, the EPA has not mandated generation shifting, but rather has factored each state's capacity for re-dispatch into the calculation of the amounts of emission reductions that are achievable to address downwind air quality. The

[141] Interpreting the Good Neighbor Provision to be sufficiently broad to authorize reliance on generation shifting is also consistent with the legislative history for the 1970 CAA Amendments. The Senate Report stated that to achieve the NAAQS, ''[g]reater use of natural gas for electric power generation may be required,'' S. Rep. No. 91–1196 at 2, which can best be achieved by shifting generation from coal-fired to natural-gas-fired generators.

[142] *See* Legal Memorandum Accompanying Clean Power Plan for Certain Issues, 137–48, *EPA–HQ–OAR–2013–0602–36872; West Virginia* v. *EPA, D.C. Cir. No. 15–1363, Brief of Amici Curia* Grid Experts Benjamin F. Hobbs, Brendan Kirby, Kenneth J. Lutz, James D. McCalley, and Brian Parsons in Support of Respondents, at 1–4, 12–14.

emission reductions are captured in state budgets, which are then implemented through the flexible CSAPR NO_X ozone season allowance trading program that allows each source to determine its own strategy for compliance, whether that be through implementation of on-site controls, re-dispatch, or the purchase of allowances. Indeed, no state would violate the provisions of the rule if sources within the state decided not to employ re-dispatch as a means of compliance. As discussed in Section VII, the EPA performed a feasibility analysis which demonstrates that regionally and for each CSAPR Update state, the trading program requirements promulgated by this rule can be met through cost-effective measures, even without re-dispatch.

Further, we note that while commenters urged EPA to allow sources to use generation shifting as a means of compliance with statewide emissions budgets, they do not explain why they believe that re-dispatch may be used by sources for compliance but that the EPA may not consider this anticipated and widely-used means of reducing emissions when quantifying the amount of reductions achievable from sources within the state. In fact, because these comments acknowledge that sources are able to implement generation-shifting for the purpose of reducing emissions, they support EPA's reliance on generation-shifting to quantify the amount of reductions required under the good neighbor provision. Moreover, these comments support the view that even if the EPA did not base the amount of required emission reductions on generation-shifting, sources would rely on generation-shifting to meet their requirements as long as it is less expensive than other emission controls.

Although the commenters contend that the consideration of shifting generation as a source of emission reductions is unprecedented, shifting generation is a well-established technique for reducing power plant emissions, which has already been incorporated into many other CAA programs. For example, when promulgating the original CSAPR rulemaking, the EPA considered shifting generation when establishing state budgets in the same manner in which the EPA has incorporated generation shifting into the analysis for this rule.[143]

Finally, the commenters have not identified a clear conflict with the EPA's justification for considering generation shifting in the context of the CPP. The CPP was designed pursuant to the authority in CAA section 111(d), while the CSAPR Update is promulgated consistent with the requirements of the good neighbor provision at CAA section 110(a)(2)(D)(i)(I). As explained earlier, the good neighbor provision is permissibly interpreted to allow the EPA to consider generation shifting when defining the ''amounts'' of emission reductions that may be required to address each states' significant contribution to nonattainment and interference with maintenance of downwind air quality. Thus, while EPA is confident that its interpretation of section 111(d) to authorize generation-shifting will be upheld, the fact that litigants have challenged the EPA's authority pursuant to section 111(d) does not affect the EPA's authority pursuant to the good neighbor provision.

Moreover, the fact that there are factual differences between the nature of CO_2 and NO_X as air pollutants, does not constrain the EPA's authority to consider shifting generation when regulating NO_X emissions pursuant to the good neighbor provision. Rather, as described earlier, both rules regulate sources in the power sector that commonly engage in generation shifting as a means of achieving emission reductions of either CO_2 or NO_X. It is thus reasonable for the EPA to consider such practices in quantifying achievable emission reductions to address downwind air quality concerns. Furthermore, the rulemakings appropriately reflect the factual differences to the extent they are relevant (*e.g.,* this rule includes assurance provisions constraining emissions in each state and CPP does not, which reflects the regional nature of NO_X and the global nature of CO_2).

Comment: Commenters contend that the EPA cannot consider generation shifting for purposes of developing state emission budgets because the Federal Energy Regulatory Commission (FERC) has exclusive authority over dispatch requirements under the Federal Power Act. These commenters claim that scheduling and dispatch are controlled by regional transmission organizations and independent system operators, pursuant to FERC approval. Additionally, the commenters note that EGUs already may have committed their capacity under long term power purchase agreements (PPAs), which the EPA lacks the authority to alter or abrogate. Other commenters contend that the EPA must at least confer with FERC to confirm that the generation shifting required by this rule do not impact grid reliability.

Response: The CSAPR Update is an air-pollution rule specifically authorized by the CAA. As discussed in response to the previous comment, shifting generation is a well-established technique for reducing power plant emissions, which has already been incorporated into many other CAA programs. This rule limits EGU NO_X emissions that interfere with downwind states' ability to attain and maintain the 2008 ozone NAAQS. The rule does not regulate any other aspect of energy generation, distribution, or sale. For these reasons, the CSAPR Update does not intrude on FERC's power under the Federal Power Act, 16 U.S.C. 791a, *et seq.,* nor does the rule alter or abrogate the PPAs to which EGUs are subject. Like any pollution limits for the power industry (of which there are many under the CAA), the CSAPR Update will indirectly impact energy markets, but those impacts do not mean that the EPA has overstepped its authority.

The CSAPR Update does not require implementation of any specific control technology or compliance strategy. As described in section VII, the emission reductions quantified in this rule are implemented through EGU participation in a flexible allowance trading program. Sources may achieve these emission reductions in any manner they choose, including the purchasing of additional allowances if a particular source is constrained to reduce its emissions. Although sources have demonstrated ability to use re-dispatch as a compliance strategy (and indeed, some commenters concede they intend to do so here), such actions are not mandated

[143] *See* 76 FR at 48280 (EPA's selection of a $500 threshold ''reflect[ed] an amount of . . . generation shifting that can be achieved for $500/ton''). For other CAA programs and rules that are based at least in part on generation-shifting, *see* S. Rep. No. 101–228, at 316 (1989) (Congress designed the Title IV acid rain provisions in the 1990 CAA Amendments in part on the ability of power plants to re-dispatch); 77 FR 9304, 9410 (Feb. 16, 2012) (in Mercury Air Toxics Rule, EPA authorized compliance extensions so that power plants could comply by generation-shifting); 70 FR 28606, 28619 (May 18, 2005) (in Clean Air Mercury Rule, EPA based emission requirements in part on the ability of power plants to generation shift); 70 FR 25162, 25256–57, 25277 (May 12, 2005) (several of CAIR's provisions were based on the ability of power plants to re-dispatch); 63 FR 57356, 57401 (Oct. 27, 1998) (NO_X SIP Call included ''changes in dispatch'' among the highly cost-effective controls that served as the basis for the required amount of reductions). In addition, several states have already adopted renewable energy measures in their SIPs for attaining and maintaining the NAAQS, and the EPA has provided initial guidance for states to do so. *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf.* For example, in 2005, EPA approved inclusion of county government commitments to purchase 5 percent of their annual electricity consumption from wind power in Maryland's SIP. 70 FR 24988 (May 12, 2005).

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by this rule. As discussed in Section VII, the EPA performed a feasibility analysis which demonstrates that regionally and for each CSAPR Update state, the trading program requirements promulgated by this rule can be met, even without re-dispatch.

Moreover, the EPA has evaluated the impact on electric reliability of the emission reductions required by this rule and found that compliance with the CSAPR Update requirements is consistent with maintaining electric reliability. For more information regarding this assessment, see the EGU NO_X Mitigation Strategies Final Rule TSD in the docket for this rule. The EPA also met with FERC during the development of the CSAPR Update to discuss compliance with the entirety of the rule, not only in relation to shifting generation. This meeting is documented in the docket for the CSAPR Update.

2. Quantifying Emission Budgets

In the proposed CSAPR Update, the EPA proposed setting emission budgets by considering monitored heat input (mmBtu) and modeled emission rates (lbs/mmBtu) from IPM. Specifically, the proposed CSAPR Update put forward a methodology to set emission budgets by multiplying monitored historical state-level heat input by model-projected 2017 state-level emission rates. The monitored historical data were based on 2014, which was the most recent complete ozone season dataset at the time of the proposal. The model-projected state-level emission rates were used to reflect EGU NO_X reduction potential. The proposed emission budgets were the lower of the calculated emission budget or the 2014 historical state-level emissions. The EPA took comment on all aspects of quantifying state emission budgets reflecting upwind EGU NO_X reduction potential.

The proposed CSAPR Update budget-setting approach differed from the finalized methodology in the original CSAPR, which used model-projected state-level emission data as emission budgets. The EPA received feedback on the finalized original CSAPR budget-setting approach through model input data submitted after the final rule that led to two revisions rules [144] and in litigation on the original CSAPR. Considering this feedback, the EPA believed that it was reasonable to update the budget-setting methodology for the proposed CSAPR Update. The proposed approach is similar to the proposed approach used to quantify emission budgets for the original CSAPR.[145]

The final rule methodology for setting emission budgets reflects the CSAPR Update proposal in that it retains the approach of multiplying historical state-level heat input by state-level emission rates that reflect EGU NO_X reduction potential. For the final CSAPR Update rule, the EPA is refining its methodology for establishing emission budgets that reflect EGU NO_X reduction potential by using historical state-level NO_X emission rates [146] adjusted by modeled NO_X reduction potential. Specifically, the final rule's approach applies the change in modeled 2017 state-level emission rates (the budget-setting base case 2017 projected rates minus the cost threshold modeling 2017 projected rates) to historical 2015 state-level NO_X emission rates,[147] such that the emission budgets assume the potential of each state to improve its historical NO_X rate by the same degree that it is projected to improve its NO_X rate when moving between the budget-setting base case 2014 projection and cost threshold projection.

This approach uses the EPA's IPM EGU NO_X reduction potential modeling in a relative sense by applying the projected 2017 change in state-level EGU NO_X emission rates to 2015 historical data. This approach is similar to the EPA's method for projecting ambient air quality concentrations described in section V. The EPA is finalizing this refinement to the proposed approach in response to comment received on the proposal. The primary improvement of this approach relevant to comment received is that it circumvents quantifying in emission budgets any modeled EGU NO_X reduction potential (*e.g.,* modeled retirements) that occurs in the budget-setting base case projection.

However, this approach also circumvents quantifying in emission budgets any known EGU NO_X reduction activities (*e.g.,* announced new SCR at existing EGUs, announced coal-to-gas conversions, or announced retirements) occurring between the historical 2015 data and the modeled projection 2017 data.

To account for known changes in the final rule budget-setting methodology, the EPA developed an adjusted historical dataset. This adjusted historical data starts with 2015 state-level monitored and reported EGU NO_X emissions and heat input. The dataset is then adjusted for three categories of known changes in the power sector occurring between 2015 and 2017: Announced new SCR at existing EGUs; announced coal-to-gas conversions; and announced retirements. These important adjustments ensure that the emission budgets established by this rule reflect EGU NO_X reductions both from already announced power sector changes and further EGU NO_X reductions quantified in the EPA's EGU NO_X reduction potential analysis. Accounting for known EGU NO_X reduction activities in establishing emission budgets ensures that the emission budgets reflect the best available information in terms of achievable EGU NO_X reductions and remaining emission levels. To account for announced new SCR at existing EGUs, the EPA adjusts the 2015 emissions at the relevant units as though the new SCR had been operating at that time (assuming no change in heat input [148] at those units). Similarly, to account for announced coal-to-gas conversions, the EPA adjusts the 2015 emissions at the relevant units as though the conversion had already taken place (assuming no change in heat input at those units). To account for announced retirements, the EPA subtracts the 2015 emissions from these units and replaces them by adding assumed emissions for an equivalent amount of generation using state-wide average emission rates after accounting for the retirement. Preserving some emissions associated with the generation from retired units, assuming that generation will be replaced by other EGUs in the state, ensures that the budget-setting approach accounts for known retirements but estimates the emission impact using generation replacement assumptions with conservatively high NO_X emission rates. In other words, the EPA assumes that the retired generation is replaced by the average remaining EGU composition within the state rather than by newer lower-emitting generation.

Comment: Commenters supported the EPA's consideration of historical monitored data to quantify emission budgets and advocated that the EPA

[144] 77 FR 34830 (June 12, 2012) and 77 FR 10324 (February 21, 2012).

[145] The original CSAPR proposal set proposed emission budgets by using an approach that considered monitored state-level heat input and modeled state-level emission rates. (75 FR 45291).

[146] The EPA notes that historical state-level ozone season EGU NO_X emission rates are publicly available and quality assured data. They are monitored using continuous emissions monitors (CEMs) data and are reported to the EPA directly by power sector sources.

[147] The EPA used 2014 historical data at proposal because that was the latest available at that time. Since then, 2015 historical data is available and the EPA is using 2015 data in the final rule because it best reflects the current state of the power sector.

[148] In this analysis the EPA used heat input as a proxy for electricity generation.

further utilize historical data in its budget-setting methodology. For example, some commenters proposed an alternative budget-setting methodology that was grounded entirely in historical data, with NO_X control assumptions applied. Commenters also suggested that the budget-setting base case projection emission rates were unduly influenced by model-projected changes for the 2017 analysis year and that this created emission budgets that did not reflect achievable NO_X emission levels.

Response: In response to these comments, the agency considered approaches to isolate model-projected changes in the power sector occurring in the budget-setting base case projection and model-projected changes that result from the application of uniform cost threshold analysis. As discussed previously, for the final rule, the EPA is refining its method for calculating emission budgets in response to these comments. In doing so, the EPA is also finalizing a budget-setting methodology that further relies on historical data, which is further aligned with comment received on the proposal.

The approach for applying this budget-setting methodology to the EPA's EGU NO_X reduction potential analysis uses a three step process, applied to each control stringency level. First, the EPA uses the state-level modeled EGU NO_X emission rate from the 2017 budget-setting base case projection and subtracts the state-level modeled EGU NO_X emission rate from the 2017 cost threshold projection (*e.g.,* $1,400 per ton).[149] This yields the EPA's assessment of policy-related EGU NO_X reduction potential in the form of a reduction in state-level NO_X emission rate. Second, the EPA subtracts this modeled change in state-level NO_X emission rate from the adjusted historical state-level EGU NO_X emission rate. This yields a cleaner state-level EGU NO_X emission rate that is grounded in historical data and reflects policy-related EGU NO_X reduction potential. Third, the EPA multiplies the resulting EGU NO_X emission rate by 2015 historical heat input. This multiplication yields state-specific ozone season EGU NO_X emission budgets for 2017 that are grounded in historical data and reflect EGU NO_X reduction potential modeled in IPM. Similar to the proposal, the final CSAPR Update establishes emission budgets as the lower of the calculated emission budget or the 2015 historical (unadjusted) state-level emissions.

In conducting the IPM modeling of each cost threshold, the EPA limited IPM's evaluation of NO_X mitigation strategies to those that can be implemented for the 2017 ozone season, which is the compliance timeframe for this rulemaking. The agency analyzed levels of uniform EGU NO_X control using IPM, where each level is represented by marginal NO_X costs listed in Table VI.C–1 in this preamble. The analysis applied these uniform levels of control to EGUs in the 48 contiguous United States and the District of Columbia, starting with 2017. The analysis included EGUs with a capacity (electrical output) greater than 25 MW, which reflects the CSAPR Update rule applicability criteria. The Ozone Transport Policy Analysis Final Rule TSD, which is in the docket for this rule, provides further details of the EPA's analysis of ozone season NO_X emission reductions occurring at each level of uniform control stringency for the 2017 ozone season.

As described in in Section V, air quality data for the CSAPR Update indicates that the District of Columbia contributes at or above the 1 percent threshold to a downwind maintenance receptor in Harford County, Maryland. Moreover, in Step 3 of the CSAPR framework, the EPA's analysis finds that there are no EGUs in the District of Columbia that meet the CSAPR Update applicability criteria (*i.e.,* EGUs with a capacity greater than 25 MW). Therefore, the EPA does not calculate or finalize an EGU NO_X ozone season emission budget for the District.

The 2015 historical data, adjusted historical data, and EGU NO_X ozone season emission budgets calculated using each cost threshold identified in the final emission budget-setting approach can be found in Tables VI.C–1 and VI.C.2.

TABLE VI.C–1—EVALUATED EGU NO_X OZONE SEASON EMISSION BUDGETS, REFLECTING EGU NO_X REDUCTIONS

[Ozone season NO_X tons]

State	2015 emissions	Adjusted historical emissions	$800 per ton emission budgets	$1,400 per ton emission budgets	$3,400 per ton emission budgets
Alabama	20,369	15,179	14,332	13,211	12,620
Arkansas	12,560	12,560	12,048	9,210	9,048
Illinois	15,976	14,850	14,682	14,601	14,515
Indiana	36,353	31,382	28,960	23,303	21,634
Iowa	12,178	11,478	11,477	11,272	11,065
Kansas	8,136	8,031	8,030	8,027	7,975
Kentucky	27,731	26,318	24,052	21,115	21,007
Louisiana	19,257	19,101	19,096	18,639	18,452
Maryland	3,900	3,871	3,870	3,828	3,308
Michigan	21,530	19,811	19,558	17,023	15,782
Mississippi	6,438	6,438	6,438	6,315	6,243
Missouri	18,855	18,443	17,250	15,780	15,299
New Jersey	2,114	2,114	2,100	2,062	2,008
New York	5,593	5,531	5,220	5,135	5,006
Ohio	27,382	27,382	23,659	19,522	19,165
Oklahoma	13,922	13,747	13,746	11,641	9,174
Pennsylvania	36,033	35,607	20,014	17,952	17,928
Tennessee	9,201	7,779	7,736	7,736	7,735
Texas	55,409	54,839	54,521	52,301	50,011
Virginia	9,651	9,367	9,365	9,223	8,754
West Virginia	26,937	26,874	25,984	17,815	17,380
Wisconsin	9,072	7,939	7,924	7,915	7,790

[149] Each state-level emission rate is calculated as the total emissions from affected sources within the state divided by the total heat input from these sources.

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TABLE VI.C–1—EVALUATED EGU NO_X OZONE SEASON EMISSION BUDGETS, REFLECTING EGU NO_X REDUCTIONS—Continued

[Ozone season NO_X tons]

State	2015 emissions	Adjusted historical emissions	$800 per ton emission budgets	$1,400 per ton emission budgets	$3,400 per ton emission budgets
22 State Region	398,596	378,641	350,062	313,626	301,899

TABLE VI.C–2—EVALUATED EGU NO_X OZONE SEASON EMISSION BUDGETS, REFLECTING EGU NO_X REDUCTIONS

[Ozone season NO_X tons]

State	2015 emissions	Adjusted historical emissions	$5,000 per ton emission budgets	$6,400 per ton emission budgets
Alabama	20,369	15,179	11,928	11,573
Arkansas	12,560	12,560	8,518	8,050
Illinois	15,976	14,850	14,248	14,054
Indiana	36,353	31,382	19,990	18,720
Iowa	12,178	11,478	10,891	10,491
Kansas	8,136	8,031	7,962	7,767
Kentucky	27,731	26,318	20,273	19,496
Louisiana	19,257	19,101	18,442	18,426
Maryland	3,900	3,871	2,938	2,926
Michigan	21,530	19,811	13,110	12,612
Mississippi	6,438	6,438	6,203	6,205
Missouri	18,855	18,443	14,673	14,555
New Jersey	2,114	2,114	1,867	1,879
New York	5,593	5,531	4,746	4,594
Ohio	27,382	27,382	18,561	18,348
Oklahoma	13,922	13,747	8,790	8,439
Pennsylvania	36,033	35,607	17,621	17,374
Tennessee	9,201	7,779	7,724	7,729
Texas	55,409	54,839	48,795	47,994
Virginia	9,651	9,367	8,619	8,416
West Virginia	26,937	26,874	17,388	17,373
Wisconsin	9,072	7,939	7,435	7,023
22 State Region	398,596	378,641	290,722	284,044

D. Multi-Factor Test Considering Costs, EGU NO_X Reductions, and Downwind Air Quality Impacts

Next, the EPA applied the multi-factor test to consider cost, available emission reductions, and downwind air quality impacts to determine the appropriate level of uniform NO_X control stringency, feasible for 2017, that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. This test evaluates these factors to determine the appropriate stopping point for quantifying upwind state obligations to address interstate ozone transport, including whether the identified downwind ozone problems (*i.e.,* nonattainment or maintenance problems) are resolved.

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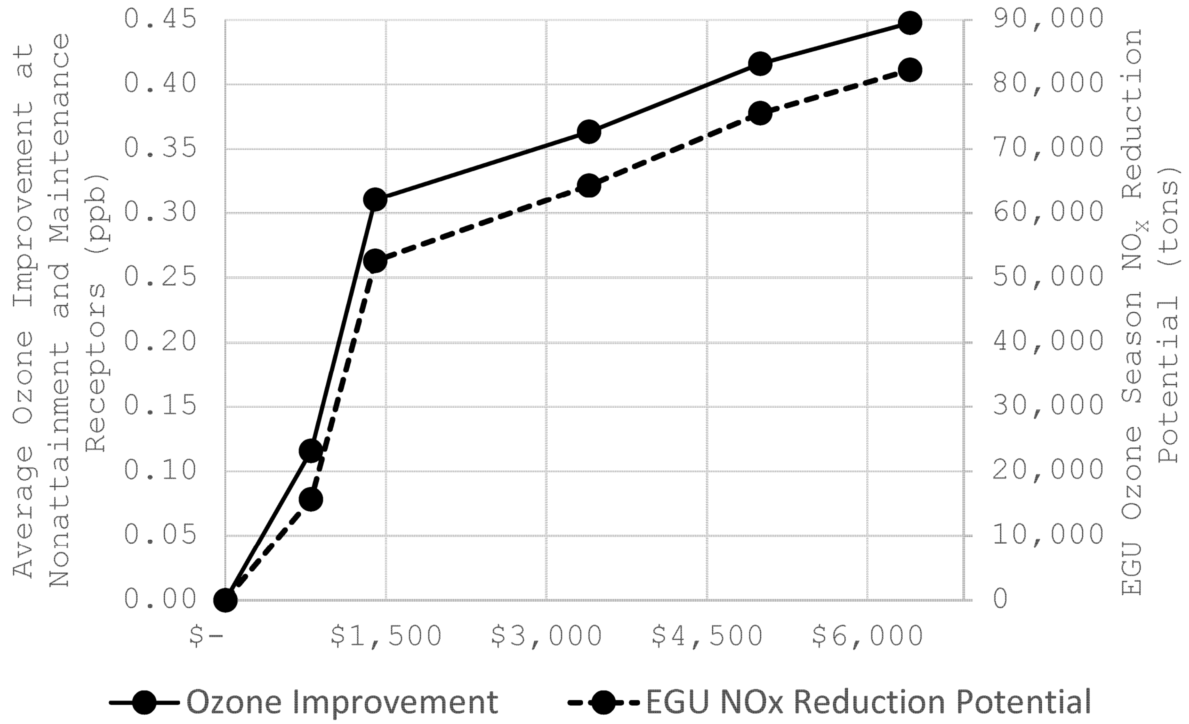
Figure VI.1. EGU Ozone Season NO_X Reduction Potential in 22 Linked States and Corresponding Total Reduction in Downwind Ozone Concentrations at Nonattainment and Maintenance Receptors for each Emission Budget Level Evaluated



Combining costs, EGU NO_X reductions, and corresponding improvements in downwind ozone concentrations results in a ''knee in the curve'' at a point where emission budgets reflect a control stringency with an estimated marginal cost of $1,400 per ton. This level of stringency in emission budgets represents the level at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized with respect to marginal cost. That is, the ratio of emission reductions to marginal cost and the ratio of ozone improvements to marginal cost are maximized relative to the other emission budget levels evaluated. Further, more stringent emission budget levels (*e.g.,* emission budgets reflecting $3,400 per ton or greater) yield fewer additional emission reductions and fewer air quality improvements relative to the increase in control costs. This evaluation shows that significant EGU NO_X reductions are available at reasonable cost and that these reductions can provide improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors for the final rule.

To assess downwind air quality impacts for each nonattainment or maintenance receptor identified in this rulemaking, the EPA evaluated the air quality change at that receptor expected from the progressively more stringent upwind EGU NO_X emission budgets quantified for each uniform NO_X control stringency level. This assessment provides the downwind ozone improvements for consideration and provides air quality data that is used to evaluate over-control.

In order to assess the air quality impacts of the various control stringencies, the EPA evaluated changes resulting from the application of the emission budgets to states that are linked to each receptor as well as the state containing the receptor. By applying each budget level to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. For states that were not linked to that receptor, the air quality change at that receptor was evaluated assuming emissions equal to the adjusted historic emission level, including Pennsylvania RACT. This method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states in order to address air quality problems at other receptors do not increase or decrease this fair share. This approach removes state equity considerations from this component of the multi-factor test and preserves the apportionment of upwind responsibility to the assessment of uniform control stringency represented by cost, which the Supreme Court found to be ''an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 134 S. Ct. at 1607.

For this assessment, the EPA used an ozone air quality assessment tool (ozone AQAT) to estimate downwind changes in ozone concentrations related to upwind changes in emission levels. This tool is similar to the AQAT tool used in the original CSAPR to evaluate changes in $PM_{2.5}$ concentrations. The ozone AQAT uses simplifying assumptions regarding the relationship between each state's change in EGU NO_X emissions and the corresponding change in ozone concentrations at nonattainment and maintenance receptors to which that state is linked. This method is calibrated using two CAMx air quality modeling scenarios that fully account for the non-linear relationship between emissions and air quality associated with atmospheric chemistry. *See* the Ozone Transport Policy Analysis Final Rule TSD for additional details.

For each emission budget level and for each receptor, the EPA evaluated the magnitude of the change in concentration and determined whether the estimated concentration would resolve the receptor's nonattainment or maintenance concern by lowering the average or maximum design values below 76 ppb, respectively.

As an example, the EPA evaluated the Harford County, Maryland receptor with all linked states and Maryland meeting emission budgets reflecting controls available at $800 per ton of NO_X emissions reduced. Adding up the state-by-state changes in air quality contributions resulting from the changes in emissions, this assessment showed a 0.1 ppb reduction in expected ozone design values. After subtracting this air quality improvement from the design values quantified in section V of this preamble, the residual design values at this site are still expected to exceed the 2008 ozone NAAQS with an average design value of 79.0 ppb and a maximum design value of 81.6 ppb. Next, the EPA evaluated this receptor with all linked states and Maryland meeting emission budgets reflecting controls available at $1,400 per ton. This assessment showed a 0.4 ppb reduction in expected ozone design values. At emission budgets reflecting $1,400 per ton, the residual design values at this site are expected to continue to exceed the 2008 ozone NAAQS with an average design value of 78.7 ppb and a maximum design value of 81.3 ppb. Next, the EPA evaluated this receptor with all linked states and Maryland meeting emission budgets reflecting controls available at $3,400 per ton. This assessment showed a 0.6 ppb reduction in expected ozone design values. At emission budgets reflecting $3,400 per ton, the residual design values at this site are expected to continue to exceed the 2008 ozone NAAQS with an average design value of 78.5 ppb and a maximum design value of 81.2 ppb. Next, the EPA evaluated this receptor with all linked states and Maryland meeting emission budgets reflecting controls available at $5,000 per ton. This assessment showed a 0.7 ppb reduction in expected ozone design values. At emission budgets reflecting $5,000 per ton, the residual design values at this site are expected to continue to exceed the 2008 ozone NAAQS with an average design value of 78.4 ppb and a maximum design value of 81.1 ppb. Next, the EPA evaluated this receptor with all linked states and Maryland meeting emission budgets reflecting controls available at $6,400 per ton. This assessment showed a 0.7 ppb reduction in expected ozone design values. At emission budgets reflecting $6,400 per ton, the residual design values at this site are expected to continue to exceed the 2008 ozone NAAQS with an average design value of 78.4 ppb and a maximum design value of 81.0 ppb.

Generally, the EPA evaluated the air quality improvements at each monitoring site for the emission budgets associated with each progressively more stringent emission budget. For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Final Rule TSD.

As part of this analysis, the EPA evaluates potential over-control with respect to whether (1) the expected ozone improvements would be sufficient or greater than necessary to resolve the downwind ozone pollution problem (*i.e.,* resolving nonattainment or maintenance problems) or (2) the expected ozone improvements would reduce upwind state ozone contributions to below the screening threshold (*i.e.,* one percent of the NAAQS).

In *EME Homer City,* the Supreme Court held that the EPA cannot ''require[] an upwind State to reduce emissions by more than the amount necessary to achieve attainment in *every* downwind State to which it is linked.'' 134 S. Ct. at 1608. On remand from the Supreme Court, the D.C. Circuit held that this means that the EPA might overstep its authority ''when those downwind locations would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations.'' *EME Homer City II,* 795 F.3d at 127. The D.C. Circuit qualified this statement by noting that this ''does not mean that every such upwind State would then be entitled to less stringent emission limits. Some of those upwind States may still be subject to the more stringent emissions limits so as not to cause *other* downwind locations to which those States are linked to fall into nonattainment.'' *Id.* at 14–15. As the Supreme Court explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 134 S. Ct. at 1609. The Court noted that ''a degree if imprecision is inevitable in tackling the problem of interstate air pollution.'' *Id.* ''Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate.'' *Id.*

Consistent with these instructions from the Supreme Court and the D.C. Circuit, the EPA first evaluated whether reductions resulting from the $800 per ton emission budgets can be anticipated to resolve any downwind nonattainment or maintenance problems (as defined in section V) and by how much. This assessment shows that the emission budgets reflecting $800 per ton would resolve maintenance problems at one downwind maintenance receptors—Philadelphia, Pennsylvania (maximum design value of 75.8 ppb). The EPA's assessment shows that no state included in the CSAPR Update is linked solely to the Philadelphia receptor that is resolved at the $800 per ton level of control stringency.

Next, the EPA evaluated whether reductions resulting from the $1,400 per ton emission budgets can be anticipated to resolve any further downwind nonattainment or maintenance problems. For the 22 CSAPR Update states, the EPA assessed further EGU NO_X reductions of emission budgets reflecting $1,400 per ton and found that the emission budgets reflecting $1,400 per ton would resolve nonattainment and maintenance problems at one downwind nonattainment receptors—Jefferson County, Kentucky (maximum design value of 75.7 ppb)—and would resolve maintenance problems at one additional downwind maintenance receptor—Hamilton County, Ohio (maximum design value of 75.1 ppb). The EPA's assessment shows that this control level does resolve the only identified nonattainment or maintenance problems to which Tennessee is linked—the Hamilton County, Ohio and Philadelphia, Pennsylvania receptors. However, no other no state included in the CSAPR Update is linked solely to these receptors that are resolved at the $1,400 per ton level of control stringency.

In light of the improvements at the maintenance receptors to which Tennessee is linked, the EPA evaluated the magnitude of those improvements and whether the air quality problems could have been resolved at a lower level of control stringency. At the emission budgets reflecting $1,400 per ton, the EPA's assessment demonstrates that the receptors to which Tennessee is linked would just be maintaining the standard, with maximum design values of 75.5 (Philadelphia) and 75.1 ppb (Hamilton County), which the EPA truncates to compare against the 2008 ozone standard. Consistent with the manner in which the EPA truncates design values to evaluate NAAQS attainment, these concentrations are equal to the level of the 2008 ozone

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NAAQS at 75 ppb. Therefore, the emission reductions that would be achieved by emission budgets reflecting $1,400 per ton would not result in air quality improvements at these receptors significantly better than the standard such that emission reductions might constitute over-control as to the receptors. On the contrary, the emission reductions achieved in upwind states by emission budgets reflecting $1,400 per ton are necessary to bring the maximum design value at the receptors into alignment with the standard. The EPA finds that, based on the information supporting this final rule, the $1,400 per ton emission budget level would not constitute over-control for Tennessee or for any other state included in the CSAPR Update.

In *EME Homer City,* the Supreme Court also held that ''EPA cannot require a State to reduce its output of pollution . . . at odds with the one percent threshold the Agency has set.'' 134 S. Ct. at 1608. The Court explained that ''EPA cannot demand reductions that would drive an upwind State's contribution to every downwind State to which it is linked below one percent of the relevant NAAQS.'' *Id.* Accordingly, the EPA evaluated the potential for over-control with respect to the one percent threshold applied in this rulemaking at each relevant emission budget level. Specifically, the EPA evaluated whether the emission budget levels would reduce upwind EGU emissions to a level where the contribution from any upwind state would be below the one percent threshold that linked the upwind state to the downwind receptors. If the EPA found that any state's emission budget would decrease its contribution below the one percent threshold to every downwind receptor to which it is linked, then it would adjust the state's reduction obligation accordingly. The EPA's assessment reveals that there is not over-control with respect to the one percent threshold at any of the evaluated uniform cost emission budget levels in any upwind state. Most relevant, the EPA finds that under the $800 per ton and $1,400 per ton emission budgets, all 22 eastern states that contributed greater than or equal to the one percent threshold in the base case continued to contribute greater than or equal to one percent of the NAAQS to at least one downwind nonattainment or maintenance receptor. For more information about this assessment, refer to the Ozone Transport Policy Analysis Final Rule TSD.

Considering the EPA's findings with respect to application of the multi-factor test and over-control, the EPA is finalizing ozone season EGU NO_X emission budgets reflecting $1,400 per ton of EGU NO_X control for all CSAPR Update states. The EPA finds that the finalized Tennessee emission budget fully addresses Tennessee's good neighbor obligation with respect to the 2008 ozone NAAQS. For the remaining CSAPR Update states, final emission budgets reflecting $1,400 per ton of EGU NO_X control represent a partial solution for these states' good neighbor obligation with respect to the 2008 ozone NAAQS.

In establishing emission budgets reflecting $1,400 per ton of EGU NO_X control, the EPA notes that combustion controls are the only EGU NO_X reduction strategy that the EPA generally considers feasible for the 2017 ozone season in quantifying emission budgets for the final CSAPR Update and that also requires new construction. For this unique reason, in developing each state emission budget, the EPA specifically considered the number of EGUs with NO_X reduction potential from installing state-of-the-art combustion controls, 2015 reliance on these EGUs for electricity generation in the state, and the magnitude of reductions relative to the resulting emission budgets.

These data indicate that nearly all of the EGU NO_X reduction potential for one state, Arkansas, comes from installing state-of-the-art combustion controls. The EPA's analysis for the final rule finds that two units at White Bluff and two units at Independence power plants in Arkansas have significant EGU NO_X reduction potential from the installation of state-of-the-art combustion controls. The NO_X reduction potential from these units is uniquely significant relative to Arkansas' resulting emission budget. The agency's analysis finds approximately 3,000 tons of ozone season NO_X reduction potential from these 4 units in Arkansas. If the EPA were to calculate a 2017 emission budget for Arkansas that includes reductions attributable to combustion controls, these reductions would be equivalent to 33 percent of Arkansas' resulting emission budget. The NO_X reduction potential from installing combustion controls has an outsized effect on Arkansas' resulting emission budget relative to other states. Arkansas is unique with respect to emission reduction potential achievable from combustion controls relative to its corresponding emission budget. In all other states covered by this rule, reduction potential from combustion controls relative to the CSAPR Update rule emission budgets is 11 percent or less. While the EPA does not anticipate that sources in any other state would have difficulty installing upgraded combustion controls for the 2017 ozone season, for the reasons described earlier, the relatively low number of expected emissions reductions from those controls means that failure of any of these sources to install such controls would not lead the state to exceed the assurance levels and incur CSAPR assurance penalties.

Further, these units at White Bluff and Independence power plants in Arkansas, combined, accounted for nearly 40 percent of the state's 2015 heat input. Compared to other CSAPR Update states, Arkansas is also uniquely situated in this regard. In all other states covered by this rule, the percentage of state-level heat input from units with reduction potential from installation of combustion controls is 20 percent or less. The CSAPR allowance trading program allows Arkansas' utilities the option to choose alternative compliance paths. However, the EPA considers that if their compliance path included combustion controls for these units, then it may be difficult to schedule outage time to upgrade all four of the Arkansas units to state-of-the-art combustion controls for the 2017 ozone season and supply adequate electricity to meet demand in the state.

If, due to the unique feasibility concerns discussed earlier, the Arkansas units could not install upgraded controls for the 2017 ozone season, Arkansas utilities could exceed the CSAPR assurance level in 2017.[150] In such circumstances, Arkansas utilities would not only need to purchase allowances for compliance, but they would also face the CSAPR assurance provision penalty, meaning that for emissions exceeding the assurance level, utilities would need to surrender three allowances for each ton of emissions.

In light of these unique circumstances, the EPA believes that it is prudent and appropriate to finalize for Arkansas a 2017 ozone season emission budget for Arkansas that does not account for EGU NO_X reduction potential from combustion controls and a 2018 ozone season emission budget for Arkansas that does account for EGU NO_X reduction potential from combustion controls. This approach provides utilities an extra year to upgrade combustion controls in the event that this is their chosen CSAPR Update compliance path. This extra year

[150] More information about CSAPR Update Rule assurance levels can be found in section VII of this document.

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allows for upgrades to be made across four shoulder seasons (fall 2016, spring 2017, fall 2017, and spring 2018).

The emission budgets that the EPA is finalizing in FIPs for the CSAPR Update rule are summarized in table VI.E–2.

TABLE VI.E–2—FINAL 2017 EGU NO_X OZONE SEASON EMISSION BUDGETS FOR THE CSAPR UPDATE RULE

[Ozone season NO_X tons]

State	2015 emissions	Adjusted historical emissions	CSAPR update rule 2017 * emission budgets
Alabama	20,369	15,179	13,211
Arkansas	12,560	12,560	12,048/9,210
Illinois	15,976	14,850	14,601
Indiana	36,353	31,382	23,303
Iowa	12,178	11,478	11,272
Kansas	8,136	8,031	8,027
Kentucky	27,731	26,318	21,115
Louisiana	19,257	19,101	18,639
Maryland	3,900	3,871	3,828
Michigan	21,530	19,811	17,023
Mississippi	6,438	6,438	6,315
Missouri	18,855	18,443	15,780
New Jersey	2,114	2,114	2,062
New York	5,593	5,531	5,135
Ohio	27,382	27,382	19,522
Oklahoma	13,922	13,747	11,641
Pennsylvania	36,033	35,607	17,952
Tennessee	9,201	7,779	7,736
Texas	55,409	54,839	52,301
Virginia	9,651	9,367	9,223
West Virginia	26,937	26,874	17,815
Wisconsin	9,072	7,939	7,915
22 State Region	398,596	378,641	316,464/313,626

* The EPA is finalizing CSAPR EGU NO_X ozone season emission budgets for Arkansas of 12,048 tons for 2017 and 9,210 tons for 2018 and subsequent control periods.

The EPA's selection of emission budgets for this rule is specific to, and appropriate for, defining near-term achievable upwind obligations with respect to the 2008 ozone NAAQS in states where a FIP is necessary. The EPA does not intend—nor does it believe it would be justified in doing so in any event—that the cost-level-based determinations in this rule impose a constraint for selection of cost levels in addressing transported pollution with respect to future NAAQS and/or any revisions to these FIPs for any other future transport rules that the EPA may develop to address any potential remaining obligation as to the current NAAQS, for which different cost levels may be appropriate.

In addition to 22 states identified previously, the EPA also assessed the potential for EGU NO_X reductions in Delaware and the District of Columbia. This assessment finds that the District of Columbia does not have any affected EGUs. As a result, despite the District of Columbia's linkage to the Harford County, Maryland receptor, the District does not have any EGU NO_X reduction potential. The EPA also has not taken action to approve or disapprove a pending good neighbor SIP addressing the 2008 ozone NAAQS. Given that the District of Columbia does not have any affected sources and the District's SIP is still before the agency, the EPA is not finalizing a FIP for the District in this action. Also, the EPA's assessment of EGU NO_X reduction potential shows zero reductions available in Delaware in 2017 at any evaluated cost threshold because they are already equivalently controlled. Given this information and the fact that Delaware's SIP is also still pending before the agency, we are not promulgating a FIP for Delaware in this rule. The EPA will consider the information developed for this rule, as appropriate, in evaluating the good neighbor SIPs for these areas,[151] and if the EPA ultimately disapproves those SIPs, the EPA will address any resulting FIP obligation separately.

The proposed CSAPR Update sought comment on whether or not to include Wisconsin in the final CSAPR Update considering that the modeling data for the proposal showed zero NO_X reduction potential for Wisconsin under the proposed EGU NO_X control stringency. Unlike our analysis at proposal, the EGU NO_X emission reduction potential analysis for the final rule shows that EGUs in Wisconsin and all 22 CSAPR Update states have EGU emission reductions available using the uniform control stringency represented by $1,400 per ton. Further, ozone season emission budgets that the EPA is finalizing in the CSAPR Update represent reductions from 2015 emission levels for Wisconsin and all 22 CSAPR Update states. The EPA is therefore including each of the 22 CSAPR Update states in the final CSAPR Update to ensure that each state achieves NO_X emission reductions to address significant contribution to nonattainment or interference with maintenance of downwind pollution with respect to the 2008 ozone NAAQS.

[151] As noted earlier, the EPA has not taken final action to approve or disapprove Delaware's good neighbor SIP addressing the 2008 ozone NAAQS.

VII. Implementation Using the Existing CSAPR NO_X Ozone Season Allowance Trading Program and Relationship to Other Rules

A. Introduction

This section addresses step four of the CSAPR framework by describing how the EPA will implement and enforce the EGU emission budgets quantified in section VI, which represent the remaining EGU emissions after reducing

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those amounts of each state's emissions that significantly contribute to downwind nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. *See* Table VI.E–2 for final emission budgets. The EPA is finalizing FIPs with respect to the 2008 ozone NAAQS for each of the 22 states covered by this rule. The FIPs will require affected EGUs to participate in the CSAPR NO_X ozone season trading program subject to the final emission budgets. The EPA is updating the CSAPR NO_X ozone season program requirements in 40 CFR part 97 to reflect these CSAPR NO_X ozone season emission budgets and final CSAPR Update Rule trading program requirements.

The CSAPR NO_X ozone season trading program is a market-based approach that implements emission reductions needed to meet the CAA's good neighbor requirements. The emission budgets establish state-level aggregate emission caps that specify the quantity of emissions authorized from affected EGUs. The EPA creates individual authorizations (''allowances'') to emit a specific quantity (*i.e.,* 1 ton) of ozone season NO_X. The total number of allowances equals the level of the emission budgets, which partially address interstate emission transport under the good neighbor provision for the 2008 ozone NAAQS. To be in compliance, each participant must hold allowances equal to its actual emissions for each control period. It may buy or sell (trade) them with other market participants. Each affected EGU can design its own compliance strategy—emission reductions and allowance purchases or sales—to minimize its compliance cost. And it can adjust its compliance strategy in response to changes in technology or market conditions. The compliance flexibility provided by the CSAPR NO_X ozone season trading program does not prescribe unit-specific and technology-specific NO_X mitigation. While the EPA establishes emission budgets that reflect emission reductions that can be achieved by certain near-term and cost effective EGU NO_X mitigation strategies (*e.g.,* turning on idled SCRs), no particular EGU NO_X reduction strategy is required for any specific EGU to demonstrate compliance with the CSAPR Update rule.

In order to ensure that each upwind state addresses its significant contribution to nonattainment or interference with maintenance and to accommodate inherent year-to-year variability in state-level EGU operations, the CSAPR NO_X ozone season trading program includes variability limits and assurance provisions. These provisions are unchanged from those established in the original CSAPR with the exception of each CSAPR Update state having a revised variability limit and assurance level that corresponds with its revised emission budget. The CSAPR assurance provisions require additional allowance surrender penalties (a total of 3 allowances per ton of emissions) [152] on emissions that exceed a state's CSAPR NO_X ozone season assurance level, or 121 percent of the emission budget.

When the EPA finalized the original CSAPR in 2011, the rule established regional trading programs designed to cost-effectively reduce transported emissions of SO_2 and NO_X from power plants in eastern states that affect air quality in downwind states. *See* 76 FR 48272 and 48273 (August 8, 2011). The EPA envisioned that this approach to implementing necessary emission reductions could be used to address transport obligations under other existing NAAQS and future NAAQS revisions. *See* 76 FR 48211 and 48246 (August 8, 2011). The EPA is finalizing implementation of the CSAPR Update emission budgets using the CSAPR NO_X ozone season allowance trading program, with certain updates. Using the familiar CSAPR trading program to implement these near-term EGU reductions for the 2008 ozone standard provides many significant advantages, including certainty in emission reductions achieved by dint of caps on emissions and air quality-assured allowance trading, ease of transition to the new emission budgets, the economic and administrative efficiency of trading approaches, and the flexibility afforded to sources regarding compliance.

The first control period for the requirements finalized in these FIPs is the 2017 ozone season (May 1, 2017–September 30, 2017). Affected EGUs within each covered state must demonstrate compliance with FIP requirements for the 2017 ozone season and each subsequent ozone season unless and until the state submits a SIP that the EPA approves as replacing the FIP, or the EPA promulgates another federal rule replacing or revising the FIP.

In this section of the preamble, the following topics are addressed: New and revised FIPs; updates to CSAPR NO_X ozone season trading requirements, including trading program structure and treatment of banked allowances; feasibility of compliance; key elements of the CSAPR trading programs; replacing the FIP with a SIP; title V permitting; and the relationship of this rule to other emission trading and ozone transport programs (NO_X SIP Call, CSAPR trading programs, CPP).

B. New and Revised FIPs

As explained in section III in this preamble, the EPA is finalizing new or revised FIP requirements only for those states where the EPA has the authority and obligation to promulgate a FIP addressing the state's interstate transport obligation pursuant to CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. That is, the EPA is finalizing new or revised FIP requirements for certain states where the EPA either found that the state failed to submit a complete good neighbor SIP or disapproved a good neighbor SIP for that state. Moreover, the EPA is only finalizing new or revised FIP requirements for those states identified in sections V and VI of this preamble, whose emissions significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in other eastern states. For those states that contribute below the one percent threshold applied in section V of this preamble, the EPA concludes that the state's emissions do not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS. There is therefore no need to impose further emission limits on sources within those states through issuance of new or revised FIP requirements.

Of the 22 states required to participate in the CSAPR NO_X ozone season trading program under this CSAPR Update, 21 states [153] already comply with the original CSAPR NO_X ozone season requirements with respect to the 1997 ozone NAAQS. For those 21 states, the EPA is revising their existing FIP requirements to require compliance with updated budgets at the levels in Table VI.E–2. One state, Kansas, has newly added CSAPR NO_X ozone season compliance requirements in this action. For Kansas, the agency is establishing new FIP requirements to require compliance with a budget at the level in Table VI.E–2.

One state, Georgia, has a continued compliance requirement under the original CSAPR NO_X ozone season program with respect to the 1997 ozone NAAQS and is not found to significantly contribute to

[152] Each excess ton above the assurance level must be met with one allowance for normal compliance plus two additional allowances to satisfy the penalty.

[153] Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

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nonattainment or interfere with maintenance of the 2008 ozone NAAQS in other states. Therefore, Georgia's CSAPR NO_X ozone season requirements (including its emission budget) continue unchanged pursuant to the state's previously-defined obligation that was quantified to address the 1997 ozone NAAQS, and the EPA is not making any changes to the existing FIP requirements for Georgia contained in 40 CFR part 52.

Three states (Florida, North Carolina, and South Carolina) are currently subject to the CSAPR NO_X ozone season trading program with respect to the 1997 ozone NAAQS under the original CSAPR. However, as described in section IV of this preamble, the phase 2 NO_X ozone season budgets [154] for these three states were remanded to the EPA for reconsideration by the D.C. Circuit in *EME Homer City II,* 795 F.3d at 138. In this final rule, the EPA finds that emissions from Florida, North Carolina, and South Carolina do not significantly contribute to nonattainment or interfere with maintenance of either the 1997 ozone NAAQS or the 2008 ozone NAAQS in other states. Accordingly, starting with the 2017 ozone season, these three states will no longer be subject to CSAPR NO_X ozone season trading program requirements and EGUs in these states will not be allocated further allowances nor obligated to demonstrate compliance with CSAPR NO_X ozone season requirements. The EPA is revising 40 CFR part 52 to remove CSAPR NO_X ozone season program requirements for these three states.

C. Updates to CSAPR NO_X Ozone Season Trading Program Requirements

For the CSAPR Update rule, the EPA is finalizing certain updates to the CSAPR NO_X ozone season trading program to transition the existing original CSAPR NO_X ozone season trading program, designed to address the 1997 ozone NAAQS, to address new requirements as to interstate emission transport for the 2008 ozone NAAQS. These changes will be effective for the 2017 ozone season control period. In this context, the EPA determines the extent to which allowances issued under emission budgets established to address interstate transport with respect to the 1997 ozone NAAQS would or would not be eligible for compliance under this rule for affected EGUs with emission budgets established to address interstate transport for the 2008 ozone NAAQS. In developing approaches to transition the CSAPR trading program, the EPA weighed several factors, including achieving the environmental goal of the CSAPR Update (*i.e.,* achieving necessary emission reductions to address interstate transport with respect to the 2008 ozone NAAQS) and feasibility of implementing the CSAPR Update rule. The EPA proposed and took comment on several approaches regarding this transition of the original CSAPR NO_X ozone season program to address interstate emission transport for the more recent 2008 ozone NAAQS.

The EPA considered whether CSAPR NO_X ozone season allowances issued in 2017 and thereafter to affected EGUs in original CSAPR states without updated CSAPR NO_X ozone season trading program budgets (*i.e.,* Georgia) can be used for compliance in the 22 CSAPR Update states and vice versa. As described later on, this final rule prohibits the use of allowances for compliance between Georgia and the CSAPR Update states because of the differences in air quality goals (*i.e.,* the 1997 ozone NAAQS versus the 2008 ozone NAAQS) and the different NO_X control stringency used to establish emission budgets necessary to achieve those air quality goals. The EPA is implementing this prohibition by establishing two distinct trading groups with distinct allowances within the CSAPR NO_X ozone season allowance trading program. The EPA provides an option for Georgia to voluntarily adopt via SIP a commensurate CSAPR Update emission budget that would obviate this prohibition by including Georgia in the trading group with the CSAPR Update states.

The EPA also considered whether, and to what extent, banked [155] 2015 and 2016 CSAPR NO_X ozone season allowances issued under original CSAPR NO_X ozone season emission budgets should be eligible for compliance in CSAPR Update states in 2017 and beyond. As described later on, this rule establishes a one-time allowance conversion that transitions a limited number of banked 2015 and 2016 allowances (approximately 99,700 allowances) for compliance use in CSAPR Update states. This allowance conversion is designed to limit the potential use of banked allowances to no more than one year of the CSAPR variability limits in order to ensure that implementation of the trading program will result in NO_X emission reductions sufficient to address significant contribution to nonattainment or interference with maintenance of downwind pollution with respect to the 2008 ozone NAAQS. However, the conversion also facilitates compliance with the CSAPR Update by carrying over some allowances that can be used for compliance.

1. Relationship of Allowances and Compliance for CSAPR Update States and States With Ongoing Original CSAPR Requirements

The final rule establishes two trading groups within the CSAPR NO_X ozone season allowance trading program. Group 2 is newly established and is comprised of the 22 CSAPR Update states. Group 1, at this time, consists of Georgia. The CSAPR Update rule ozone season Group 1 and Group 2 trading programs are codified under 40 CFR part 97, subparts BBBBB for Group 1 and EEEEE for Group 2, to enact the EGU NO_X ozone season emission budgets for the 2008 ozone NAAQS. Section 52.38(b) has been amended to update which sources are subject to the requirements of the respective subparts of part 97 for control periods after 2016.

The EPA will issue distinct allowances for these trading groups, CSAPR NO_X ozone season Group 1 allowances and CSAPR NO_X ozone season Group 2 allowances, for the 2017 ozone season control period and subsequent control periods. Covered entities may transfer, trade (buy and sell), and bank (save) these allowances. Pursuant to the CSAPR trading program regulations, compliance is demonstrated by holding and surrendering one allowance for each ton of ozone season NO_X emitted during the control period (*i.e.,* ozone season). The CSAPR Update finalizes provisions governing compliance that prohibit the use of Group 1 allowances for compliance in Group 2 states or the use of Group 2 allowances for compliance in Group 1 states.[156] Aside from revised emission budgets for CSAPR NO_X ozone season Group 2 states and the prohibition of using Group 1 allowances for compliance in Group 2 states, and vice versa, the CSAPR Update rule NO_X ozone season trading programs' implementation requirements (*e.g.,* monitoring, reporting, assurance provisions) are substantively identical to the original CSAPR NO_X ozone season trading program.

[154] CSAPR phase 1 NO_X ozone season emission budgets are effective for 2015 and 2016 while phase 2 NO_X ozone season emission budgets would be effective starting with the 2017 ozone season.

[155] Allowances that were not used for compliance and were saved for use in a later compliance period.

[156] There are limited exceptions for circumstances where a source becomes subject to a requirement to hold additional Group 1 allowances after Group 1 allowances have been converted to Group 2 allowances, as discussed in section IX in this preamble.

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In the original CSAPR SO_2 annual allowance trading program, the EPA discussed its concern with permitting the use of allowances for compliance between groups of states linked to air pollution problems that are more easily resolved and groups of states linked to air pollution problems that are more persistent. The EPA was concerned that allowance trading between these groups of states could undermine the capacity of the rule to achieve the emission reductions required by the good neighbor provision of the CAA. Specifically, trading between these groups could lead to greater emission reductions in states linked to more easily resolved air pollution problems and fewer emission reductions in states linked to more persistent air pollution problems. This concern arose, in part, because the EPA identified different levels of significant contribution to nonattainment or interference with maintenance for these groups of states. As a result, these groups' emission budgets were established using different levels of control stringency. Allowing trading between groups of states with emission budgets representing substantially different uniform costs could lead to allowance transfers from EGUs in states with less stringent emission budgets to EGUs in states with more stringent emission budgets.[157] The EPA was concerned that allowing trading between such groups of states could increase the risk of emissions within a state exceeding the CSAPR emission budget or assurance level. For these reasons, the original CSAPR rulemaking prohibited the use of CSAPR SO_2 Group 1 allowances in SO_2 Group 2 states and vice versa.

In similar fashion, in order to ensure that the CSAPR NO_X ozone season trading program implements emission reductions needed to meet the CAA's good neighbor requirements for the CSAPR Update states, the EPA is finalizing a prohibition on allowance usage between Georgia and the CSAPR Update states. Specifically, for the final CSAPR Update rule, the EPA determines that allowances issued in 2017 and thereafter under the original CSAPR will not be eligible for compliance in the 22 CSAPR Update states, and vice versa. The EPA is finalizing this prohibition because states participating in the original CSAPR NO_X ozone season program (*i.e.,* Georgia) are doing so to address interstate emission transport for the 80 ppb 1997 ozone NAAQS, while CSAPR Update States are addressing interstate emission transport for the 75 ppb 2008 ozone NAAQS. The air quality assessment performed for this rule shows that ozone pollution problems with respect to the 75 ppb standard are relatively more robust than ozone problems with respect to the 80 ppb standard. Further, due in part to these differences in ozone pollution risk represented by the two standards, the EPA has identified different levels of significant contribution to nonattainment or interference with maintenance for these groups and the corresponding emission budgets and assurance levels reflect different levels of EGU NO_X control stringency. The original CSAPR NO_X ozone season emission budgets and assurance levels reflect $500 per ton of NO_X emissions reduced while the CSAPR Update emission budgets and assurance levels reflect $1,400 per ton of NO_X emissions reduced. The EPA finds this substantial difference in uniform cost could lead to allowance transfers from EGUs in Georgia to EGUs in CSAPR Update states. Specifically, the EPA notes that the ratio of marginal cost of ozone season NO_X control reflected in these emission budgets is nearly three-to-one, which is similar to the three-to-one assurance provision allowance surrender penalty that is incurred on emissions that exceed any state's assurance level (121 percent of the emission budget). The EPA finds that allowing trading between Georgia and the CSAPR Update states could increase the risk that emissions in CSAPR Update states exceed their emission budget or their assurance level.

The EPA does not expect that the prohibition of using CSAPR Update rule NO_X ozone season Group 2 allowances for compliance in Group 1 states will create significant concern regarding feasibility of compliance for Group 1 states. Georgia's ozone season emissions have been well below its original CSAPR NO_X ozone season emission budget for several years. The EPA anticipates that units within the state will continue to meet compliance obligations even without the ability to use CSAPR Update rule NO_X ozone season Group 2 allowances for compliance. Further, the EPA is quantifying an optional CSAPR Update rule EGU NO_X ozone season emission budget for Georgia, using the same methods and uniform cost as budgets for CSAPR Update states. This emission budget reflects protection of downwind air quality under the 2008 ozone NAAQS. If Georgia chooses to adopt this emission budget via a revised SIP submittal, then the EPA believes that such a SIP submission may be approvable and Georgia may thereby opt into the CSAPR Update rule NO_X ozone season Group 2 trading program and use the CSAPR Update rule NO_X ozone season Group 2 allowances for compliance.

Comment: Commenters suggested that if states subject to the original CSAPR for the 1997 ozone NAAQS are not found to significantly contribute to nonattainment or interfere with maintenance for the 2008 ozone NAAQS, then allowances issued in those states should not be part of the remedy, since there is no physical connection between NO_X allowances issued for those states and the downwind ozone nonattainment or maintenance problem that another state's reductions must address for a different NAAQS.

Response: In light of the specific differences in ozone pollution problems addressed, level of significant contribution to nonattainment or interference with maintenance, and marginal cost of NO_X reduction used to establish emission budgets for the original CSAPR and the CSAPR Update rule, the EPA agrees that it is reasonable to prohibit the use of CSAPR Update rule NO_X ozone season Group 1 allowances for compliance in Group 2 states and vice versa, as described previously.

Comment: Commenters suggested that there should not be a prohibition on using allowances between these groups of states and that the CSAPR assurance provisions are sufficient to ensure that emission reductions are made in upwind states.

Response: The assurance provisions provide limited flexibility around the finalized emission budgets developed using uniform control stringency to accommodate inherent variability in average power sector operations. For example, assurance levels are intended to accommodate specific unusual events, such as sudden and unexpected outages of a unit, or severe weather. The assurance level is intended to function as a not-to-exceed cap that includes both the state budget—established to reduce significant contribution to and interference with maintenance of the 2008 ozone NAAQS in downwind states—and the variability limit. The flexibility provided by the assurance provisions is not designed to address interstate trading in the case of two groups of states that are addressing different ozone pollution problems, levels of significant contribution to nonattainment or interference with maintenance, or levels of EGU NO_X reduction stringency in emission budgets. Further, as described previously, the EPA finds that were it to

[157] 76 FR at 48263–64.

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authorize use of allowances issued to EGUs in Georgia for compliance in CSAPR Update states, the risk of emissions in a CSAPR Update state exceeding its emission budget or assurance level would increase.

2. Use of Banked Vintage 2015 and 2016 CSAPR NO_X Ozone Season Trading Program Allowances for Compliance in CSAPR Update States

In this subsection, the EPA describes its approach to transition a limited number of allowances that were banked in 2015 and 2016 under the original CSAPR EGU NO_X ozone season emission budgets into the allowances that can be used for compliance in CSAPR Update states in 2017 and thereafter. As proposed, the EPA is finalizing a limit on the number of banked allowances carried over based on the need to assure that the CAA objective of the CSAPR Update is achieved. This approach transitions some allowances for compliance to further ensure feasibility of implementing the CSAPR Update rule.

Specifically, the EPA is including in this final rule a method for ensuring that emissions in the CSAPR Update region do not exceed a specified level—this is, emissions up to the sum of the states' seasonal emissions budgets and variability limits—as a result of the use of banked allowances. The method is captured in a formula or ratio, the numerator of which is the total number of banked allowances at the end of the 2016 ozone season and the denominator of which is 1.5 times the aggregated variability limits finalized in this rule. The ratio is then applied to the banked vintage 2015 and 2016 allowances in each account to yield the number of banked allowances available to each account holder in 2017.[158]

When proposing this approach, the EPA described how sources in states with new or updated budgets could use all of their banked allowances, but at a turn-in ratio significantly higher than one under which only one allowance would be used to cover each ton of emissions (*e.g.,* a four-for-one or a two-for-one turn-in ratio). The EPA proposed to use turn-in ratios calculated using the proposed formula described above—essentially the same formula that the EPA is including in this final rule. At proposal, the EPA explained that the ratio of the banked vintage 2015 and 2016 allowances to the aggregated ozone season variability limits was designed to limit the magnitude of the emission impact of sources' use of banked allowances to that of the emissions level that would result from all states emitting up to the sum of their budgets and their variability limits for one or two years. (*See* 80 FR 75747.) The formulaic ratio when applied to the actual bank and emissions levels would yield a conversion factor for banked allowances that would be used to implement the proposed emissions limitation.

The final approach described in this section—a one-time conversion of aggregated banked vintage 2015 and 2016 allowances to 2017 vintage allowances equivalent to 1.5 years of the aggregated CSAPR Update variability limits—is virtually identical to the approach we laid out in the NPRM. In particular, it is identical to the proposal in terms of the formula used to assess the number of banked allowances relative to the CSAPR Update variability limits. Further, the value for the principal input to this formula that the EPA is updating in this final rule—the aggregated variability limits—is very similar to the value for this input at proposal.[159] The EPA has refined this approach to converting the banked allowances based on comments we received that urged us to simplify implementation. The final approach limits the influence of banked allowances via a one-time conversion, which has the same impact on the allowance bank as an ongoing turn-in ratio, but provides simplified implementation of the CSAPR Update rule. Further, because the EPA will perform the conversion at one time and each allowance going forward will equate to one ton of emissions, the EPA does not find it necessary to finalize rounding the conversion ratio to the nearest whole number.

The denominator in the conversion formula—1.5 times the states' aggregated variability limits—represents the number of banked allowances that will be available for use toward compliance with the CSAPR Update. Under the CSAPR implementation framework, variability limits are established to allow the units in a state to emit above the state's emission budget in a single control period when necessary because of year-to-year variability in power sector operations. The variability limits operate in conjunction with, but are distinct from, the state emission budgets. The purpose of the state emission budgets is to ensure that each state achieves necessary emission reductions, as required under CAA section 110(a)(2)(D)(i)(I). The purpose of the variability limits, and the assurance provisions that require additional allowances to be surrendered when emissions from covered sources within a state exceed those limits, is to ensure that the requirement for each state to reduce emissions necessary to address its downwind air quality impacts is implemented in a manner consistent with normal year-to-year variability in power sector operations while keeping any emissions above the budget within acceptable limits.

In the proposal, the EPA requested comment on a range of turn-in ratios for banked allowances derived from the formula described previously, including a four-for-one ratio based on the sum of covered states' variability limits for one year and a two-for-one ratio based on the sum of covered states' variability limits for two years. Commenters expressed a wide range of views, from those advocating for no use of banked allowances to those advocating for the use of all banked allowances with no turn-in ratio, as well others advocating for turn-in ratios between these extremes. However, commenters generally did not address the specific topic of whether one, two, or a different number of years of variability limits would represent an appropriate quantity of banked allowances to allow to be used for compliance with the CSAPR Update.

The EPA has determined that it is appropriate to use as the formula denominator the sum of covered states' variability limits for 1.5 years. As noted above, the purpose of the variability limits is to accommodate year-to-year variability in power sector operations at the state level. In theory, a bank based on the sum of all covered states' variability limits would be sufficient to accommodate such variability for all states simultaneously—in other words, the maximum amount of permissible emissions consistent with the purpose and design of the variability limits—for one year. Because it is unlikely that normal year-to-year power sector variability would cause all states to need to exceed their emissions budgets in the same year, the EPA considers the sum of the states' variability limits for one year a reasonable maximum for the number of allowances that would ever need to be used for compliance to address potential variability in power sector operations. However, the EPA's experience with implementing market-based trading programs is that in

[158] As discussed in section IX of the preamble, banked allowances held in compliance accounts for sources in Georgia will not be converted and will be excluded from the conversion ratio calculation.

[159] At proposal, the aggregated variability limits totaled approximately 60,000 tons and in the final rule the aggregated variability limits total approximately 65,000 tons.

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historical practice most sources typically do not use every available allowance for compliance, but instead keep some in reserve in order to ensure compliance (*e.g.,* to avoid penalties in the event of unforeseen emissions and/or problems with preliminary data calculations). The EPA believes that using the states' variability limits for 1.5 years instead of one year provides sources with sufficient allowances to accommodate maximum year-to-year variability in power sector operations while also addressing the manner in which allowance holdings are actually managed and used. Thus, the EPA believes that providing allowances equivalent to 1.5 years of covered states' variability limits fulfills the primary purpose we described in our proposal—limiting the use of banked allowances to no more than one year of states' aggregated variability limits—while acknowledging the historical practice in market-based trading programs of sources keeping some allowances in reserve from year to year in order to provide planning and operating flexibility over multi-year periods. The EPA believes that this ratio provides an appropriate balance of these considerations, while providing a bank any larger would be inconsistent with the rule's purpose of achieving emission reductions required by CAA section 110(a)(2)(D)(i)(I).

The numerator in the conversion formula is the number of banked allowances to be converted. At proposal, the EPA anticipated, based on 2014 emissions data, that there would be approximately 210,000 banked allowances following the 2015 and 2016 ozone seasons. As commenters correctly predicted, based on more recent data, the size of the anticipated bank is now larger. Based on 2015 emissions data, the EPA anticipates that there will be approximately 350,000 banked allowances entering the CSAPR NO_X ozone season trading program by the start of the 2017 ozone season control period.[160] As explained in more detail below, this anticipated total of banked allowances reflects the fact that the seasonal NO_X emissions budgets established in CSAPR are to a significant extent not acting to constrain actual NO_X emission levels during the ozone season. Affected units overall are emitting less than their budgeted levels by a substantial margin and therefore do not have to use all of their allowances to comply with the requirements of CSAPR; as a result, the bank is growing substantially, especially relative to the emissions reductions that this rule is designed to achieve.

This amount of anticipated banked allowances is greater than the sum of all the state emission budgets established in this CSAPR Update and is roughly five times the total emission reduction potential that informs the emission budgets imposed by this rule. This number of anticipated banked allowances is also approximately five times larger than the aggregated CSAPR Update variability limits. Without imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive ozone seasons.

In prior ozone season emissions trading programs, such as the Ozone Transport Commission's NO_X Budget Program and the NO_X Budget Trading Program implemented in conjunction with the NO_X SIP Call, allowance deduction provisions (in some cases known as ''flow control'') were included in order to prevent banked allowances from being used in a single ozone season in quantities that would result in excess total emissions. Similarly under the CSAPR Update rule, the conversion ratio together with the assurance provisions will address the large size of the existing CSAPR bank with respect to the 2017 ozone season.

Limiting the influence of the banked allowances is critical to achieving the goal of reducing ozone formation, because reduction in ozone depends on reductions in precursor emissions contemporaneous with the meteorological conditions conducive to the formation of ozone. Hence the rule is designed with ozone season-specific budgets intended to achieve emission reductions by the 2017 ozone season in order to assist downwind states with meeting the July 2018 Moderate area attainment date for the 2008 ozone NAAQS. *See North Carolina,* 531 F.3d at 911–12 (instructing the EPA to coordinate upwind state emission reductions with downwind attainment deadlines). Other Clean Air Act programs designed to address public health and environmental problems that result from cumulative emissions permit sources to comply by over-controlling emissions in earlier years and using the resulting banked reductions to offset emissions in later years. In contrast, states, and when acting to meet its FIP obligations, the EPA, must ensure that the goal of improved air quality will be achieved and can do so only if emissions are reduced to specified levels during each ozone season.

This approach to limiting the influence of banked allowances also serves the goal of ensuring that emission reductions are achieved in each state. A bank of allowances that is five times the CSAPR Update variability limit would increase the risk of EGUs exceeding their states' CSAPR assurance levels, and thereby impede the ability of the assurance provisions to meaningfully limit emissions in each state. These circumstances would undermine compliance with CAA section 110(a)(2)(D)(i)(I), which requires that ''[e]ach state must eliminate its own significant contribution to downwind pollution.'' *North Carolina,* 531 F.3d at 921. The assurance provisions, as finalized in the original CSAPR rulemaking, were designed to address this requirement by imposing a penalty in the event that EGUs exceed the state assurance levels. 76 FR at 48294–98. If EGUs' incentive to constrain emissions is compromised by the availability of a large bank of allowances, the EPA could no longer ensure that appropriate state-level emissions reductions are achieved.

While the bank of allowances reflects actions taken by sources in CSAPR to reduce emissions, it also reflects other factors unique to the regulatory history of CSAPR. In particular, the CSAPR budgets were established based on information available in 2010 and 2011. As promulgated in 2011, CSAPR required the budgets to be implemented in 2012 (Phase 1) and 2014 (Phase 2). As a result of litigation, the emissions budgets did not take effect until 2015. Between 2011 and 2015, the power sector responded to increases in natural gas supply, declines in natural gas prices, and increasing penetration of wind and other low- or zero-emitting renewable energy resources. Consequently, by the time the CSAPR ozone season budgets were implemented in the 2015 ozone season, they were no longer binding on state emission levels, even though they were anticipated to be binding when developed in 2011. The original CSAPR emission budgets for the 2015 ozone season were about 628,000 tons in aggregate, but actual emissions were about 451,000 tons, resulting in a substantial bank of allowances after the 2015 ozone season. In addition, based on emissions data for May and June of 2016 (*i.e.,* the first two months of the

[160] This allowance bank size was quantified as the observed allowance bank at the conclusion of 2015 plus an estimate of allowances likely to be banked in 2016, assuming that 2016 emissions would be unchanged from 2015 levels. These data rely on 40 CFR part 75 emission reporting and are available in the EPA's Air Markets Program Data, available at *http://ampd.epa.gov/ampd/.*

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2016 ozone season under the trading program), ozone season NO_X emissions have declined 15 percent compared to the comparable period in 2015, which we anticipate will lead to a yet larger bank of allowances. In this final rule, the 2017 emission budgets plus the 21 percent variability limits total about 381,000 tons in aggregate, compared to 2015 emissions from the relevant states of about 399,000 tons. The bank of CSAPR allowances fostered in part by the unique circumstances of CSAPR's implementation is thus of a size that is so large relative to the budgets under this final CSAPR Update rule that, if all of the banked allowances were used without restriction, all states would exceed their emissions budgets for several successive ozone seasons. In that case, use of the bank would impede the achievement of the reductions needed to reduce ozone levels and assist downwind states with attainment and maintenance of the NAAQS by the 2017 ozone season. For these reasons, the implementation of the conversion ratio derived from the formula that is established in the final rule is necessary to limit the use of banked allowances and assure that reductions will actually occur and contribute to improved air quality in time to assist downwind states with meeting their attainment dates.

Some commenters objected to any limitation on the use of banked allowances, in part noting the additional compliance flexibility that banked allowances provide. But as explained above, without limitation, the number of banked allowances could undermine the capacity of the rule to achieve the emission reductions required by the good neighbor provision of the CAA—timely emission reductions in upwind areas that are necessary to avoid significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS in downwind areas. Specifically, the CSAPR Update establishes emission budgets that represent the remaining EGU emissions after reducing those amounts of each state's emissions that significantly contribute to downwind nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states, as required under CAA section 110(a)(2)(D)(i)(I). In other words, the CSAPR Update establishes an emission budget for each state that is its good neighbor obligation. If made available in its entirety for compliance with the CSAPR Update, then the anticipated 350,000 banked allowances would inherently increase the risk of states exceeding their emission budget by providing a total number of allowances for compliance in 2017 that is more than double the 22 state sum of emission budgets. The CSAPR allowance trading program already provides some flexibility in the form of the CSAPR variability limits and corresponding assurance levels to allow states to meet their good neighbor obligation while respecting inherent variability in electricity generation. However, the anticipated 350,000 banked allowances, if fully available for compliance, would also increase the risk of EGUs exceeding their states' CSAPR assurance level by providing allowances for compliance greater than five times the CSAPR variability limit. These excess allowances could be used for compliance irrespective of the need to achieve the CAA good neighbor obligation while complying with typical year-to-year variability on which the assurance levels are based. The allowance bank would thereby further undermine the capacity of the rule to achieve the emission reductions required by the good neighbor provision of the CAA by increasing the risk that emissions would exceed not only the emission budgets, but also the assurance levels.

The EPA believes that allowing for banking of excess emission reductions is a positive element of a trading-based program such as this one. Banking encourages early reductions, provides certainty, and creates flexibility in order to achieve the public health goal more cost-effectively and reliably. When use of banked allowances can undermine the environmental goal rather than help to achieve it, however, it is reasonable and appropriate to restructure the use of banked allowances. For these reasons, when the EPA finalized the original CSAPR provisions, the agency explicitly reserved its authority to eliminate or revise allowances issued in a given compliance year. The existing regulations for the current NO_X ozone season trading program explain that an allowance is ''a limited authorization to emit one ton of NO_X during the control period in one year.'' 40 CFR 97.506(c)(6). The regulations continue by providing the Administrator the ''authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' *Id.* 97.506(c)(6)(ii). The regulations also clearly state that such allowances do not constitute property rights. *Id.* 97.506(c)(7). The EPA also notes that banked allowances were accrued against 2015 and 2016 implementation of seasonal emission budgets that were established to address interstate emission transport for the 80 ppb 1997 ozone NAAQS. Banked compliance instruments with respect to the 1997 ozone NAAQS in 2015 or 2016 are not inherently interchangeable with emission reductions needed to address interstate emission transport for the 75 ppb 2008 ozone NAAQS starting in 2017.

However, provided that it can do so without jeopardizing the good neighbor objectives of the CSAPR Update rule, the EPA believes that permitting some allowances banked under the original CSAPR to be used to meet compliance with the CSAPR Update can facilitate compliance with the requirements of the latter. As described in section VI, the EPA is establishing emission budgets that it finds to be feasible for the 2017 ozone season. As a result, the EPA believes that it is feasible to implement the final CSAPR Update rule emission budgets that the EPA is promulgating in this action, even without availability of banked allowances for compliance. However, in order to ensure implementation feasibility, the EPA is finalizing an approach that transitions a limited number of banked allowances into the CSAPR NO_X ozone season Group 2 program for compliance starting with the 2017 ozone season. By providing for the use of some banked allowances for compliance with the CSAPR Update rule, the EPA provides immediate but limited compliance flexibility that will support the feasibility of meeting emission budgets for the 2017 ozone season and variation in power sector operations. The CSAPR Update assurance level reflects the upper bound variation in power sector generation that the EPA would expect in any given year. Thus, the carryover of converted banked allowances equal to 1.5 years' worth of variability limits provides the affected fleet with the ability to accommodate potential variation from the mean in its load and emission patterns in the initial year of the program and also maintain a small reserve of allowances, while balancing the need to ensure that emissions are reduced, on average, to the level of the budgets and within the assurance levels in subsequent years. For a further discussion of additional implementation feasibility provided by this approach, see section VII.C.

Considering these factors—especially the EPA's obligation to achieve the NO_X emission reductions needed to address transport with respect to the 2008 NAAQS—the EPA believes it is reasonable—even required—to restrict

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the number of banked allowances carried over.

To enable the use of banked 2015 and 2016 vintage allowances for compliance with the CSAPR Update, the EPA is finalizing a one-time conversion that transitions a number of allowances equivalent to 1.5 years of the sum of states' CSAPR NO_X ozone season Group 2 variability limits (the variability limits are 21 percent of the regional total emission budgets), or approximately 99,700 allowances. The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or ''true-up'') for the 2016 ozone season program is completed. The EPA will use an equation to derive the ratio by dividing the number of all 2015 and 2016 post-true-up banked CSAPR NO_X ozone season allowances being converted by 1.5 times the sum of the 2017 CSAPR Update variability limits quantified in Table VII.C–2 in this preamble. As soon as practicable and not later than March 1, 2018, which is the compliance deadline for the 2017 control period, and pending notification of all allowance holders, the EPA will freeze allowance accounts and convert the original CSAPR NO_X ozone season 2015 and 2016 banked allowances to the 2017 vintage CSAPR Update rule NO_X ozone season Group 2 allowances. These allowances may then be used in 2017 and thereafter on a 1-to-1 (one allowance to one ton of ozone season emissions) basis for compliance in Group 2 states.

Dividing the bank by 1.5 times the collective variability limits results in the ratio that the EPA will apply to convert each source's banked 2015 and 2016 original CSAPR NO_X ozone season allowances to 2017 CSAPR Update rule NO_X ozone season Group 2 allowances. The resulting post-conversion bank will be equivalent to 1.5 times the sum of states' CSAPR NO_X ozone season Group 2 variability limits, or approximately 99,700 allowances. Based on current data, the EPA notes that this conversion ratio would be approximately 3.5 to 1, but the ratio could be lower or higher depending on 2016 emissions. By instituting the one-time conversion of banked 2015 and 2016 allowances, the EPA is limiting the use of such allowances for purposes of assuring that emission reductions necessary to address interstate transport with respect to the 2008 ozone standard are achieved.

As of the conversion date (see 40 CFR 97.526(c)(1)), the EPA will convert all 2015 and 2016 allowances held in any account, other than a Georgia source's compliance account, to Group 2 allowances. This includes banked 2015 and 2016 allowances held in accounts in non-CSAPR Update states (*i.e.,* Florida, North Carolina, and South Carolina). The ratio will be determined by dividing the number of allowances held in all such accounts (*i.e.,* every general account and every compliance account except for a compliance account for a Georgia source) by 1.5 times the sum of the variability limits for all states other than Georgia. Starting with the 2017 ozone season control period, only CSAPR NO_X ozone season Group 2 allowances can be used for compliance with the CSAPR Update rule ozone season program. Any remaining CSAPR NO_X ozone season 2015 and 2016 allowances that are not converted to Group 2 allowances may only be used for compliance by affected sources in states that are subject to the original CSAPR ozone season program to meet obligations for the 1997 ozone NAAQS (the only such state is Georgia).

A source in the state of Georgia that chooses to have some or all of its banked 2015 and 2016 allowances converted to Group 2 allowances may move any of its 2015 and 2016 banked allowances out of a compliance account and into a general account. These allowances in the general account will then be subject to conversion to Group 2 allowances.

The EPA proposed and took comment on a range of options for how to treat the use of banked 2015 and 2016 CSAPR NO_X ozone season allowances by EGUs in the 22 CSAPR Update states. As described previously, the EPA proposed that sources in states with new or updated budgets could use all of their banked allowances, but at a ratio significantly higher than one allowance to cover each ton (*e.g.,* at a four-for-one turn-in ratio). Additionally, the proposed CSAPR Update solicited comment on less and more restrictive approaches to address use of the CSAPR EGU NO_X ozone allowance bank. Specifically, the EPA sought comment on: (1) Allowing banked 2015 and 2016 CSAPR NO_X ozone allowances to be used for compliance with the CSAPR Update for the 2008 ozone NAAQS starting in 2017 at a one-for-one ratio, or (2) completely disallowing the use of banked 2015 and 2016 CSAPR NO_X ozone allowances for compliance with the CSAPR Update for the 2008 ozone NAAQS starting in 2017. The EPA also solicited comment on whether and how the assurance provision penalty might be increased, in conjunction with any of the above approaches, to address the relationship of the allowance bank to emissions occurring under this revised program from 2017 onward. At this time, the EPA is not changing the assurance provision penalty or its application.

Comment: Some commenters suggested that implementation by way of ongoing turn-in ratios would be cumbersome and complicated because it requires affected EGUs to hold allowances for compliance that are equivalent to differing ratios of tons of emissions.

Response: The EPA agrees with the commenters who observed that an allowance trading program in which a CSAPR NO_X ozone season allowance issued in 2017 and thereafter would be worth one ton of emissions while a CSAPR NO_X ozone season allowance issued in 2015 or 2016 would be worth less than one ton of emissions is overly complex. These differing emission equivalents of otherwise similar compliance tools (*i.e.,* allowances) would add a layer of complexity to ongoing compliance demonstrations. Implementing a ratio by way of a one-time conversion, instead, has the same impact on emission reductions as an ongoing turn-in ratio in that the emissions equivalent of the banked allowances will be reduced consistent with the ratio, but the implementation of the ratio through a one-time conversion simplifies implementation of the CSAPR Update rule, which supports efficient and accurate compliance planning.

Comment: Some commenters requested that the EPA not limit the use of banked vintage 2015 and 2016 CSAPR NO_X ozone season allowances in the final CSAPR Update, suggesting that the EPA had not demonstrated that use of these allowances would undermine the goals of the CSAPR Update. These commenters suggested that the assurance levels are adequately protective of the CSAPR Update emission reduction requirements.

Response: The EPA disagrees with these comments. As discussed previously, the EPA anticipates a large number of banked allowances entering the 2017 CSAPR ozone season control period. Allowing unlimited use of this magnitude of vintage 2015 and 2016 CSAPR NO_X ozone season allowances in the 2017 control period and going forward would put the emission reduction requirements of the CSAPR Update rule in jeopardy and undermine the realization of the emission reductions needed under the good neighbor provisions of the CAA to avoid significant contribution to nonattainment and interference with

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maintenance of the 2008 ozone NAAQS in downwind areas.

Comment: Some commenters recommended that the EPA completely disallow the use of banked 2015 and 2016 CSAPR NO_X ozone allowances for compliance with the CSAPR Update for the 2008 ozone NAAQS starting in 2017.

Response: A key feature of allowance trading programs is that they provide sources an economically efficient strategy for integrating current and future compliance. Banking of allowances for later use also creates incentives to make early emission reductions, which often result in improved air quality earlier than otherwise required. The EPA has seen early reductions and banking in implementing other trading programs over the past 20 years, such as the Acid Rain Program and the NO_X SIP Call. The EPA believes such an economic incentive, and the associated environmental benefits, is conditioned on the expectation that the resulting banked allowances will have some value in the future of that program. The approach that the EPA is finalizing provides a means for the existing 2015 and 2016 CSAPR NO_X ozone season allowances to retain some value, while appropriately mitigating the potential adverse impact of the allowance bank on the emission-reducing actions needed from affected EGUs in states with obligations to address interstate transport for the 2008 ozone NAAQS.

Comment: Commenters contend that discounting allowances by a turn-in ratio essentially penalizes sources for early action.

Response: Commenters did not provide quantitative analysis that the turn-in ratio would reduce the overall economic value of the allowance holdings nor even address the question of whether or how the diminution of the number of allowances available would affect the value of each individual allowance or that of the overall bank—especially in view of the fact that the NO_X emissions budgets are more constraining. Because the allowance bank value is a product of both allowance quantity and allowance price, the conclusion that any reduction in quantity inherently reduces the bank value is flawed because it ignores the likely increase in price. Similarly, it merits noting the high likelihood that some portion of the banked allowance price reflects larger dynamics in the power markets, such as lower natural gas prices in recent years, as opposed to explicit early actions.

D. Feasibility of Compliance

In practice, the EGU emission budgets that the EPA is finalizing in this action are achievable for each of the 22 states through operating and optimizing existing SCR controls, operating existing SNCR controls, installing state-of-the-art combustion controls, shifting generation to lower NO_X–emitting or non-emitting units, using allowances that the EPA has allocated to EGUs (including banked allowances), or obtaining allowances on the allowance market. The EPA believes that this rule provides sufficient lead time to comply with the 2017 ozone season requirements.[161]

To further examine the compliance feasibility of the state NO_X ozone season budgets, the EPA performed an analysis of state-level achievable NO_X ozone season emissions for 2017 that is independent of the IPM-based assessment used to establish the emission budgets. This analysis relied on the most recent ozone season data for 2015. For the covered states, these data were adjusted to account for announced retirements, announced new SCR at existing units, and announced coal-to-gas conversions at existing units.[162] The EPA then applied certain control assumptions directly to the reported unit-level data. Specifically, this analysis applied EGU NO_X reductions for turning on idled SCR, optimizing all SCR to historically demonstrated NO_X emission rates, installing state-of-the-art combustion controls, and turning on idled SNCR.

The EPA evaluated the feasibility of turning on idled SCRs for the 2017 ozone season. Based on past practice, the EPA finds that idled controls can be restored to operation in no more than a few months. This timeframe is informed by many electric utilities' previous, long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during non-ozone season months. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. It was quite typical for SCRs to be turned off following the September 30 end of the ozone season control period. These controls would then be put in protective lay-up for several months of non-use before being returned to operation by May 1 of the following ozone season. In the 22 state CSAPR Update region, 2005 EGU NO_X emission data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining seven non-ozone season months of the year.[163] Based on EGUs' past experience and the frequency of this practice, the EPA finds that idled SCRs can be restored to operation in no more than a few months. Further, because turning on idled SCRs requires inherently more steps than fully operating existing operating SCR or turning on idled SNCR, the EPA finds that these additional EGU NO_X reduction strategies are also feasible within a few months. The lead-time for compliance with this rule is longer than this timeframe. More details on these analyses can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

The EPA also finds that, generally,[164] state-of-the-art combustion controls require a short installation time—typically, four weeks to install along with a scheduled outage (with order placement, fabrication, and delivery occurring beforehand). Feasibility of installing combustion controls was examined by the EPA in the original CSAPR where industry demonstrated the ability to install LNB controls on a large unit (800 MW) in under six months. More details on these analyses can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

As described in section VI, to establish emission budgets, the EPA made a data-informed assumption with respect to the reasonable achievable SCR NO_X rate (0.10 lbs/mmBtu) for units that are not operating SCR optimally. In order to independently evaluate whether emission budgets that rely on this assumption are achievable, the EPA used actual SCR rates for existing units that reflect demonstrated unit-level achievable SCR performance. Specifically, the EPA used the lower of 2015 NO_X rates (the most recent demonstrated achievable SCR NO_X rate) and each unit's third lowest historical ozone season NO_X rate. This approach

[161] As described in Section VI, the EPA is finalizing for Arkansas a 2017 ozone season emission budget that does not account for EGU NO_X reduction potential from combustion controls and a 2018 ozone season emission budget for Arkansas that does account for EGU NO_X reduction potential from combustion controls. This approach provides utilities an extra year to upgrade combustion controls in the event that this is their chosen CSAPR Update compliance path. This extra year allows for upgrades to be made across 4 shoulder seasons (fall 2016, spring 2017, fall 2017, and spring 2018).

[162] These adjustments are performed in the same way as the adjusted historic emissions described in section VI.

[164] This is true with one exception. The EPA finds that for Arkansas it is reasonable to delay EGU NO_X reduction potential for certain new combustion controls until 2018 and therefore gives Arkansas a 2017 budget that does not reflect these controls and a 2018 budget that does reflect these controls. This issue is discussed further in Section VI.

reflects SCR units operating in a manner consistent with demonstrated SCR performance capability at each unit. This analysis does not account for further EGU NO_X reduction potential from shifting generation to lower NO_X–emitting or non-emitting units. As discussed in section VI and further in the EGU NO_X Mitigation Strategies Final Rule TSD, the EPA believes shifting generation to lower NO_X-emitting or non-emitting units is feasible to implement for the 2017 ozone season but the agency has not developed an approach to assess generation shifting that is independent of the IPM-based assessment discussed previously.

The EPA's analysis showed that, with known fleet changes and accounting for NO_X reduction potential from SCR, SNCR, and combustion controls, all CSAPR Update rule states would be at or below their 2017 CSAPR Update rule assurance level while continuing to otherwise operate consistent with 2015 behavior. The analysis showed that, with known changes occurring prior to 2017, optimizing SCR and SNCR, and installing combustion controls, the 22 states would lower their emissions to approximately 306,000 tons—approximately 3 percent below their aggregated CSAPR Update rule budgets, and each state would be below its assurance level. Moreover, this analysis does not reflect the NO_X reduction potential from generation shifting that is also available for compliance planning. The state-level summary of this 2017 analysis is provided in Table VII.D–1. For further discussion of implementation feasibility, see the EGU NO_X Mitigation Strategies Final Rule TSD.[165]

TABLE VII.D–1—FINAL 2017 EGU NO_X OZONE SEASON EMISSION BUDGETS, ASSURANCE LEVEL, AND COMPLIANCE FEASIBILITY ANALYSIS

[Tons]

State	Final 2017 * EGU NO_X emission budgets	Final 2017 EGU NO_X assurance level	Compliance feasibility analysis
Alabama	13,211	15,985	13,673
Arkansas	12,048	14,578	8,362
Illinois	14,601	17,667	13,892
Indiana	23,303	28,197	25,325
Iowa	11,272	13,639	11,070
Kansas	8,027	9,713	7,845
Kentucky	21,115	25,549	21,269
Louisiana	18,639	22,553	18,250
Maryland	3,828	4,632	3,815
Michigan	17,023	20,598	17,960
Mississippi	6,315	7,641	6,296
Missouri	15,780	19,094	16,326
New Jersey	2,062	2,495	2,048
New York	5,135	6,213	5,406
Ohio	19,522	23,622	16,481
Oklahoma	11,641	14,086	13,039
Pennsylvania	17,952	21,722	17,262
Tennessee	7,736	9,361	6,569
Texas	52,301	63,284	52,647
Virginia	9,223	11,160	8,670
West Virginia	17,815	21,556	12,236
Wisconsin	7,915	9,577	7,813
22 State Region	316,464	....	306,252

* The EPA is finalizing CSAPR EGU NO_X ozone season emission budgets for Arkansas of 12,048 tons for 2017 and 9,210 tons for 2018 and subsequent control periods.

The allowance trading program used to implement the emission reductions in this rulemaking further promotes compliance feasibility. With this approach, an individual source has the flexibility to forgo any physical changes to its combustion or post-combustion process and simply acquire allowances from another source for compliance. Therefore, any unit-specific limitations in regard to permitting, installing, and/or modifying controls or other elements of plant operation do not jeopardize compliance, as the sources have alternative compliance options.[166] Allowance markets are well established, liquid, and will carry a number of already available banked allowances. Regarding market liquidity, the EPA observes that as of August 15, 2016 (part way through the second CSAPR NO_X ozone season compliance period) more than 1,200 private transfers have taken place involving more than 260,000 CSAPR NO_X ozone season allowances.[167] In particular, the combined flexibility of a bank and a liquid market ensures that any unit with unique circumstances regarding its control configuration can continue to operate in its current fashion. Trading flexibility further enhances system reliability because affected units may cover emissions from any reliability-relevant operations with allowances available in the marketplace.

Stakeholders have a history and familiarity with trading programs. Congress has enacted, and the EPA has promulgated, many rules that allow EGUs and other sources to meet their emission limits by trading allowances

[165] The EPA notes that a state can instead require non-EGU NO_X emission reductions through a SIP, if they choose to do so.

[166] The EPA does not anticipate that restarting an existing and permitted idled post-combustion NO_X control device would trigger any new permitting requirements.

[167] Allowance transaction data are available in EPA's Air Markets Program Data, at *http://ampd.epa.gov/ampd/*.

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with other sources. In a trading program, the EPA authorizes a source to meet its emission limit by purchasing emission allowances generated from other sources, typically ones that implement or enhance their pollution control devices to reduce emissions to the point where they are able to sell allowances. As a result, the availability of trading reduces overall costs to the industry by using the marketplace to incentivize particular sources that have the lowest control costs to implement and operate pollution controls.

The combination of control optimization feasibility, recent trends in emission reductions, on-the-way emission reductions, allowance trading, a pre-existing bank, and assurance levels support the feasibility of the CSAPR Update rule 2017 emission budgets finalized in this action.

Further supporting the feasibility of this rule's compliance obligation is the trend in recent emission reductions. While 2014 ozone season NO_X emissions for the 22 covered states were approximately 466,000 tons, they dropped by 14 percent in 2015 to 400,000. Moreover, the 2016 ozone season emissions are anticipated to be approximately 380,000 tons. This pace of reduction illustrates the speed and adaptability in the fleet's response to market conditions. It shows a trend in emission reductions that is consistent with the level of reductions anticipated by the CSAPR Update rule budgets.

Comment: The EPA received comment highlighting the significant drop in the CSAPR Update rule budgets for 2017 relative to the CSAPR phase 1 and phase 2 budgets finalized in the original CSAPR rulemaking to address the 1997 ozone standard. Some commenters asserted this significant percent difference between the two illustrated a feasibility concern.

Response: The EPA views a comparison of the original CSAPR phase 1 and 2 budgets as a poor metric for assessing feasibility of sources' compliance with the budgets being finalized in the CSAPR Update rule. As noted previously, states are already well below their current CSAPR budgets: Reported 2015 emissions for the 21 states subject to the NO_X ozone season trading program pursuant to both the original CSAPR rulemaking and the CSAPR Update rule total 390,000 tons in aggregate. For these 21 states, CSAPR phase 1 budgets aggregate to 535,000 tons and phase 2 budgets aggregate to 502,000 tons. Thus, aggregate 2015 emissions from these states are already more than 100,000 tons below the original CSAPR budgets. Based upon the first two quarters of emissions data, 2016 emissions are anticipated to be even lower. These actual emissions make a more appropriate assessment of what emission reductions are feasible for the 2017 ozone season. Moreover, CSAPR Update rule states have limited flexibility to exceed the emission budgets if needed for compliance feasibility by using banked allowances.

E. FIP Requirements and Key Elements of the CSAPR Trading Programs

The original CSAPR established a NO_X ozone season allowance trading program that allows affected sources within each state to use allowances from other sources within the same trading group for compliance, pursuant to certain monitoring requirements as codified in 40 CFR part 75. In the CSAPR NO_X ozone season trading program, sources are required to hold one CSAPR ozone season allowance for each ton of NO_X emitted during the ozone season. The EPA is utilizing that same regional trading approach, with updated emission budgets, trading groups, and certain additional revisions described later on, as the compliance remedy implemented through the FIPs to address interstate transport for the 2008 ozone NAAQS. The EPA is using the existing NO_X ozone season allowance trading system that was established under CSAPR in 40 CFR part 97, subpart BBBBB for Group 1, and as promulgated in Subpart EEEEE for Group 2, to implement the emission reductions identified and quantified in the FIPs for this action.

1. Applicability

In this rule, the EPA is finalizing the same applicability provisions as the original CSAPR, without change. Under the general CSAPR applicability provisions, a covered unit is any stationary fossil-fuel-fired boiler or combustion turbine serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW, which is producing electricity for sale, with the exception of certain cogeneration units and solid waste incineration units. *See* 76 FR 48273 (August 8, 2011), for a discussion on applicability in the final CSAPR rule. The EPA is finalizing the same applicability provisions as the original CSAPR for the CSAPR Update rule NO_X ozone season trading program Groups 1 and 2. *See* 40 CFR 97.504 and 40 CFR 97.804. The EPA is codifying these provisions as described in section IX.

2. State Budgets

The EPA is promulgating CSAPR NO_X ozone season emission budgets, as provided in table VII.E–1 in this preamble and in 40 CFR 97.810, for the 22 states in this final rule.[168] This includes the NO_X ozone season emission budgets, new unit set-asides, and Indian country new unit set-asides for 2017 and beyond.

The EPA is establishing new or revised CSAPR NO_X ozone season emission budgets for the 22 eastern states subject to FIPs in this final rule to address interstate transport for the 2008 ozone NAAQS. For the 21 of these 22 states that are currently covered by the original CSAPR ozone season program, the requirement to comply with the budgets established to address the 2008 ozone NAAQS will replace the current requirement to comply with the budgets established to address the 1997 ozone NAAQS.[169] For Kansas, which is newly brought into the CSAPR NO_X ozone season program, the EPA is finalizing a new EGU NO_X ozone season emission budget designed to address interstate transport for the 2008 ozone standard.

The EPA is implementing the emission budgets finalized in this rule by allocating allowances to sources in those states equal to the budgets for compliance starting in 2017. The EPA is finalizing allowance allocations for existing units for CSAPR NO_X ozone season Group 2 states through this rulemaking. Portions of the state budgets will be set aside for new units, and the EPA will use the processes set forth in the CSAPR regulations to annually allocate allowances to the new units in each state from the new unit set-asides.

3. Allocations of Emission Allowances

For states participating in the CSAPR NO_X ozone season Group 2 program, the

[168] The 22 states are: Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

[169] As discussed in section IV.C, Iowa, Maryland, Michigan, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Virginia, West Virginia, and Wisconsin will no longer be subject to an obligation to reduce emissions to address the 1997 ozone NAAQS after 2016, so for these states the requirement to comply with the budgets established under this rule will succeed the current requirement to comply with the budgets established to address the 1997 ozone NAAQS. Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, and Tennessee remain subject to an obligation to reduce emissions to address the 1997 ozone NAAQS, but because the budgets established in this rule are established with regard to the more stringent 2008 ozone NAAQS, the EPA is coordinating compliance requirements and allowing compliance with the budgets established under this rule to serve the purposes of meeting these states' interstate transport obligations with regard to both the 1997 ozone NAAQS and the 2008 ozone NAAQS.

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EPA will issue CSAPR NO_X ozone season Group 2 allowances to be used for compliance starting with the 2017 ozone season. This section explains that, for most states, the EPA is allocating these allowances up to each state's budget to existing units and new units in that state by applying the same allocation methodology finalized in the original CSAPR. This methodology considers both a unit's historical heat input and its maximum historical emissions. *See* 76 FR 48284, August 8, 2011. A different approach is taken for Alabama, Missouri, and New York, as described later on. This section also describes allocation to the new unit set-asides and Indian country new unit set-asides in each state; allocation to units that are not operating; and the recordation of allowance allocations in source compliance accounts.

a. *Allocations to existing units.* The EPA will implement each state's EGU NO_X ozone season emission budget in the CSAPR NO_X ozone season Group 2 trading program by allocating the number of emission allowances to covered units [170] within that state equal to the tonnage of that specific state's budget, as calculated in section VI. *See* Table VI.E–2. The portion of a state budget allocated to existing units in that state is the state budget minus the state's new unit set-aside and minus the state's Indian country new unit set-aside. The new unit set-asides are portions of each budget reserved for new units that might locate in each state or in Indian country in the future. For the existing source level allocations, see the TSD called, ''Unit Level Allocations and Underlying Data for the CSAPR for the 2008 Ozone NAAQS,'' in the docket for this rulemaking. The only allowance allocations that are being updated in this final rule are allocations of NO_X ozone season allowances under the CSAPR NO_X ozone season Group 2 program. This final rule does not change allowance allocations for the CSAPR NO_X ozone season Group 1 trading program or allocations of CSAPR SO_2 or NO_X annual allowances.

For the purpose of allocations, the original CSAPR regulations defined an ''existing unit'' as one that commenced commercial operation prior to January 1, 2010. For the 22 states subject to FIPs in this rulemaking, the EPA is modifying the definition of an ''existing unit'' for purposes of the NO_X ozone season Group 2 program to include those units that commenced commercial operation prior to January 1, 2015. This change will allow these units to be directly allocated allowances from each state's budget as existing units and will allow the new unit set-asides to be fully reserved for any future new units locating in covered states or Indian country. The EPA did not propose, and is not finalizing, any change in the definition of ''existing units'' for sources located in states subject to the original CSAPR regulations (*i.e.,* sources located in Georgia with respect to allocation of the CSAPR NO_X ozone season Group 1 allowances, and sources located in all covered states with respect to allocations of CSAPR SO_2 or NO_X annual allowances).

The EPA proposed to apply the methodology finalized in the original CSAPR for allocating emission allowances to existing units. This methodology allocates allowances to each unit based on the unit's share of the state's heat input, limited by the unit's maximum historical emissions. As discussed in the original CSAPR final rule (*See* 76 FR 48288–9, August 8, 2011), the EPA finds this allowance allocation approach to be fuel-neutral, control-neutral, transparent, based on reliable data, and similar to allocation methodologies previously used in the NO_X SIP Call and Acid Rain Program. The EPA is therefore finalizing the continued application of this methodology for allocating allowances to existing sources in this final rule (except as otherwise noted later on with respect to existing sources in Alabama, Missouri, and New York).

This final rule uses the average of the three highest years of heat input data out of a consecutive five-year period to establish the heat input baseline for each unit. These heat input data are used to calculate each unit's proportion of state-level heat input (the unit's three year average heat input divided by the state's average heat input). As a first step, the EPA applies this proportion to the total amount of existing unit allowances to be allocated to quantify unit-level allocations. However, the EPA constrains the unit-level allocations so as not to exceed the maximum historical baseline emissions, calculated as the highest year of emissions out of a consecutive eight-year period.[171] The proposal evaluated 2010–2014 heat input data and 2007–2014 emissions data, which was the most recent data available at that time. The final rule relies on 2011–2015 heat input data and 2008–2015 emission data, which is currently the most recent complete dataset.[172]

For the states of Alabama, Missouri, and New York, the EPA is not applying the methodology described previously. Instead, for these states only, the EPA is allocating allowances to existing units in the state according to methodologies for allocating ozone season NO_X allowances under the current CSAPR NO_X Ozone Season Trading Program that have been adopted into state regulations and submitted to the EPA for approval as SIP revisions, but with the states' methodologies applied to the final budgets established in this rule. This approach is consistent with the proposal, in which the EPA indicated that where a state had adopted state regulations to govern the allocation of allowances under the current CSAPR NO_X ozone season program and had included those regulations in an approved SIP revision, if the state regulations by their terms would govern allocations under a revised budget, or if it was clear how the state's approved methodology could be used by the EPA to compute allocations using the revised budget, the state's regulations or methodology would be used to govern the allowance allocations under the final rule. These three states have adopted state regulations regarding the allocation of CSAPR allowances for ozone season NO_X emissions and have made SIP submittals seeking incorporation of the regulations into their SIPs. Although the EPA has not acted on those SIP submittals (because they concern the current NO_X ozone season trading program to which the sources in these three states will no longer be subject after 2016), the EPA has determined that it is clear how the allocation methodologies reflected in the state-adopted regulations can be used to compute allocations under the final budgets for this rule. The EPA took comment in the proposal on this topic. As explained in the proposal, these possible approaches could avert the need for a state to submit another SIP revision to implement the same allocation provisions under this rule that the state has already implemented or sought to implement under CSAPR before adoption of this rule. Since the agency received no adverse comments on using this modified allocation approach for states with an EPA-approved SIP revision under the current rule, the EPA is finalizing this approach

[170] As described previously in applicability criteria.

[171] The EPA's allocation methodology also considers whether unit-level allocations should be limited because they would otherwise exceed emission levels that are permissible under the terms of consent decrees. However, in this instance the EPA's analysis indicates that consideration of consent decree limits does not alter the unit-level allocations.

[172] *See* the CSAPR Allowance Allocations Final Rule TSD for further description of the allocation methodology.

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for these three states.[173] Further discussion of how these three states' methodologies were used to determine the allocations of allowances to existing units in the states is included in the CSAPR Allowance Allocations Final Rule TSD.

As discussed later on, states have several options under CSAPR to submit SIP revisions which, if approved, may result in the replacement of the EPA's default allocations with state-determined allocations for control periods in 2018 or later years. The provisions described previously will not preclude any state from submitting an alternative allocation methodology for later compliance years through a SIP revision. *See* section VII.F for further details on the development of approvable SIP submissions.

b. *Allocations to new units.* Consistent with the revision to the definition of ''existing unit'' described earlier, for purposes of the final rule a ''new unit'' that is eligible to receive allocations from the ''new unit set-aside'' for a state includes any covered unit that commences commercial operation on or after January 1, 2015, as well as a unit that becomes covered by meeting applicability criteria subsequent to January 1, 2015; a unit that relocates to a different state covered by a FIP promulgated by this final rule; and an ''existing'' covered unit that stops operating for two consecutive years but resumes commercial operation at some point thereafter. To the extent that states seek approval of SIPs with different allocation provisions than those provided by CSAPR, these SIPs may also define new units differently.

The EPA is also finalizing allocations to a new unit set-aside (NUSA) for each state equal to a minimum of 2 percent of the total state budget, plus the projected amount of emissions from planned units in that state. For instance, if planned units in a state are projected to emit 3 percent of the state's NO_X ozone season emission budget, then the new unit set-aside for the state would be set at 5 percent, the sum of the minimum 2 percent set-aside plus an additional 3 percent for planned units. This is the same approach currently used to implement the NUSA for all CSAPR trading programs. *See* 76 FR 48292. Pursuant to the CSAPR regulations, new units may receive allocations starting with the first year they are subject to the allowance-holding requirements of the rule. If the allowances in the NUSA remain unallocated to new units, the allowances from the set-asides are redistributed to existing units before each compliance deadline. For more detail on the CSAPR new unit set-aside provisions, *see* 40 CFR 97.811(b) and 97.812.

TABLE VII.E–1—FINAL EGU NO_X OZONE SEASON NEW UNIT SET-ASIDE AMOUNTS, REFLECTING FINAL EGU EMISSION BUDGETS

[Tons]

State	Final 2017 * EGU NO_X emission budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons) [1]	Indian country new unit set-aside amount (tons)
Alabama	13,211	2	255	13
Arkansas*	12,048/9,210	2/2	240/185	
Illinois	14,601	2	302	
Indiana	23,303	2	468	
Iowa	11,272	3	324	11
Kansas	8,027	2	148	8
Kentucky	21,115	2	426	
Louisiana	18,639	2	352	19
Maryland	3,828	4	152	
Michigan	17,023	4	665	17
Mississippi	6,315	2	120	6
Missouri	15,780	2	324	
New Jersey	2,062	9	192	
New York	5,135	5	252	5
Ohio	19,522	2	401	
Oklahoma	11,641	2	221	12
Pennsylvania	17,952	3	541	
Tennessee	7,736	2	156	
Texas	52,301	2	998	52
Virginia	9,223	6	562	
West Virginia	17,815	2	356	
Wisconsin	7,915	2	151	8
22 State Region	316,464/313,626			

[1] New-unit set-aside amount (tons) does not include the Indian country new unit set-aside amount (tons).

* The EPA is finalizing CSAPR EGU NO_X ozone season emission budgets for Arkansas of 12,048 tons for 2017 and 9,210 tons for 2018 and subsequent control periods.

c. *Allocations to new units in Indian Country.* Clean Air Act programs on Indian reservations and other areas of Indian country over which a tribe or the EPA has demonstrated that a tribe has jurisdiction are implemented either by a tribe through an EPA-approved tribal implementation plan (TIP) or the EPA through a FIP. Tribes may, but are not required to, submit TIPs. Under the EPA's Tribal Authority Rule (TAR), 40 CFR 49.1–49.11, the EPA is authorized

[173] In the case of Missouri, the allocations also reflect the state's comments regarding the use of the state's methodology to establish the allocations.

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to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit and get EPA approval of a TIP. *See* 40 CFR 49.11(a); see also 42 U.S.C. 7601(d)(4). To date, no tribes have sought approval of a TIP implementing the good neighbor provision at CAA section 110(a)(2)(D)(i)(I) with respect to the 2008 ozone NAAQS. The EPA has therefore determined that it is necessary and appropriate for EPA to implement the FIPs in any affected Indian reservations or other areas of Indian country over which a tribe has jurisdiction. There are no existing units that would qualify as "covered units" under the final CSAPR Update in Indian country located in the states covered by this rule.

The EPA is finalizing its proposal to apply the CSAPR approach for allocating allowances to any new units locating in Indian country. Under the CSAPR approach, allowances to possible future new units locating in Indian country are allocated by the EPA from an Indian country new unit set-aside established for each state with Indian country. *See* 40 CFR 97.811(b)(2) and 97.812(b). The EPA reserves 0.1 percent of the total state budget for new units in Indian country within that state (5 percent of the minimum 2 percent new unit set-aside, without considering any increase in a state's new unit set-aside amount for planned units). Because states generally have no SIP authority in these areas, the EPA will continue to allocate such allowances to sources locating in such areas of Indian country within a state over which a tribe or EPA has demonstrated that a tribe has jurisdiction, even if the state submits a SIP to replace the applicable FIP. 40 CFR 52.38(b)(9)(vi) and (vii) and 52.38(b)(10). Unallocated allowances from a state's Indian country new unit set-aside are returned to the state's new unit set-aside and allocated according to the methodology described previously.

d. *Allocations to units that do not operate and the new unit set-aside.* The EPA is finalizing its proposal to apply the CSAPR approach for allocating to units that do not operate and to the new unit set-aside. The EPA is codifying the existing CSAPR provision under which a covered unit that does not operate for a period of two consecutive years will receive allowance allocations for a total of up to five years of non-operation. 40 CFR 97.811(a)(2). This approach mitigates concerns that loss of allowance allocations could be an economic consideration that would cause a unit, which would otherwise retire, to continue operations in order to retain ongoing allowance allocations. Pursuant to this provision, starting in the fifth year after the first year of non-operation, allowances allocated to such units will instead be allocated to the new unit set-aside for the state in which the non-operating unit is located. This approach allows the balance of allowance allocations to shift over time from existing units to new units, aligned with transition of the EGU fleet from older generating resources to newer ones. Allowances in the new unit set-aside that are not used by new units are reallocated to existing units in the state. The EPA proposed to retain this timeline for allowance allocation for non-operating units and it is finalizing that proposal.

4. Variability Limits, Assurance Levels, and Penalties

In the original CSAPR, the EPA developed assurance provisions, including variability limits and assurance levels (with associated compliance penalties), to ensure that each state will meet its pollution control obligations and to accommodate inherent year-to-year variability in state-level EGU operations.

The original CSAPR budgets, and the updated CSAPR emission budgets finalized in this document, reflect EGU operations in an "average year." However, year-to-year variability in EGU operations occurs due to the interconnected nature of the power sector and from changing weather patterns, changes in electricity demand, or disruptions in electricity supply from other units or from the transmission grid. Recognizing this, the trading program provisions finalized in the original CSAPR rulemaking include variability limits, which define the amount by which an individual state's emissions may exceed the level of its budget in a given year to account for this variability in EGU operations. A state's budget plus its variability limit equals a state's assurance level, which acts as a cap on each state's NO_X emissions during a control period (that is, during the May-September ozone season in the case of this rule). The new NO_X ozone season trading program provisions established for affected sources in the 22 states subject to this rule contain equivalent assurance provisions.

These variability limits ensure that the trading program can accommodate the inherent variability in the power sector while also ensuring that each state eliminates the amount of emissions within the state, in a given year, that must be eliminated to meet the statutory mandate of section 110(a)(2)(D)(i)(I). Moreover, the structure of the program, which achieves required emission reductions through limits on the total number of allowances allocated, assurance provisions, and penalty mechanisms, ensures that the variability limits only allow the amount of temporal and geographic shifting of emissions that is likely to result from the inherent variability in power generation, and not from decisions to avoid or delay the installation of necessary controls.

To establish the variability limits in the original CSAPR, the EPA analyzed historical state-level heat input variability as a proxy for emissions variability, assuming constant emission rates. *See* 76 FR 48265, August 8, 2011. The variability limits for ozone season NO_X in the original CSAPR were calculated as 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading program were then codified in 40 CFR 97.510 along with the state budgets. The EPA performed an updated analysis to ensure the 21 percent variability limits used in the original CSAPR rule were also valid for purposes of implementing the new and revised budgets finalized in this rule. The EPA's updated analysis demonstrates that variability considering recent data remains consistent (*i.e.,* within 1 percent) with the assessment conducted for the original CSAPR rulemaking. This analysis may be found in the TSD called, Power Sector Variability Final CSAPR Update TSD, in the docket for this rulemaking. The EPA is therefore setting variability limits for the 22 states covered by this rule calculated as 21 percent of each state's new or revised budget and codifying these variability limits in 40 CFR 97.810.

Table VII.E–2 shows the final EGU NO_X ozone season Group 2 emission budgets, variability limits, and assurance levels for each state.

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TABLE VII.E–2—FINAL EGU NO_X OZONE SEASON EMISSION BUDGETS REFLECTING EGU NO_X MITIGATION AVAILABLE FOR 2017 AT $1,400 PER TON, VARIABILITY LIMITS, AND ASSURANCE LEVELS

[Tons]

State	EGU 2017 * NO_X ozone season group 2 emission budgets	EGU NO_X ozone season group 2 variability limits	EGU NO_X ozone season group 2 assurance levels
Alabama	13,211	2,774	15,985
Arkansas	12,048/9,210	2,530/1,934	14,578/11,144
Illinois	14,601	3,066	17,667
Indiana	23,303	4,894	28,197
Iowa	11,272	2,367	13,639
Kansas	8,027	1,686	9,713
Kentucky	21,115	4,434	25,549
Louisiana	18,639	3,914	22,553
Maryland	3,828	804	4,632
Michigan	17,023	3,575	20,598
Mississippi	6,315	1,326	7,641
Missouri	15,780	3,314	19,094
New Jersey	2,062	433	2,495
New York	5,135	1,078	6,213
Ohio	19,522	4,100	23,622
Oklahoma	11,641	2,445	14,086
Pennsylvania	17,952	3,770	21,722
Tennessee	7,736	1,625	9,361
Texas	52,301	10,983	63,284
Virginia	9,223	1,937	11,160
West Virginia	17,815	3,741	21,556
Wisconsin	7,915	1,662	9,577
22 State Region	316,464/313,626		

* The EPA is finalizing CSAPR EGU NO_X ozone season emission budgets for Arkansas of 12,048 tons for 2017 and 9,210 tons for 2018 and subsequent control periods.

The assurance provisions include penalties that are triggered when the state emissions as a whole exceed the state's assurance level. The original CSAPR provided that, when the EGUs in a state exceed that state's assurance level in a given year, some of those sources will be assessed a 3-to-1 allowance surrender on the excess tons, as described later on. Each excess ton above the assurance level must be met with one allowance for normal compliance plus two additional allowances to satisfy the penalty. The penalty is designed to deter state-level emissions from exceeding assurance levels. This was described in the original CSAPR as air quality-assured trading that accounts for variability in the electricity sector but also ensures that the necessary emission reductions occur within each covered state.[174] If the EGU emissions in a state do not exceed the state's assurance level, no penalties are incurred by any source. Establishing assurance levels with compliance penalties therefore responds to the court's holding in *North Carolina* requiring the EPA to ensure that sources in each state are required to eliminate emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in another state.[175]

To assess the penalty under the assurance provisions, the EPA evaluates whether any state's total EGU emissions in a control period exceeded the state's assurance level, and if so, the EPA then determines which owners and operators of units in the state exceeded the common designated representative's (DR) share of the state assurance level and, therefore, will be subject to an allowance surrender requirement. Since a DR often represents multiple sources, the EPA evaluates which groups of units at the common DR level had emissions exceeding the respective common DR's share of the state assurance level. This provision is triggered only if two criteria are met: (1) The group of sources and units with a common DR are located in a state where the total state EGU emissions for a control period exceed the state assurance level; and (2) that group with the common DR had emissions exceeding the respective DR's share of the state assurance level. The EPA is finalizing equivalent assurance provisions, modified only as necessary to allow the provisions to work in the same way despite the presence of factors that could otherwise alter their operation, such as converted banked allowances, the possible election by Georgia to bring its sources into the Group 2 program through a SIP revision, and the possible election by other states to bring non-EGUs and additional allowances into the program through SIP revisions. These differences are discussed in section IX in this preamble. For more information on the CSAPR assurance provisions generally, *see* 76 FR 48294 (August 8, 2011).

[174] *See* 76 FR 48266, August 8, 2011: "Far from excusing any state from addressing emissions within the state that significantly contribute to nonattainment or interfere with maintenance in other states, these variability limits ensure that the system can accommodate the inherent variability in the power sector while ensuring that each state eliminates the amount of emissions within the state, in a given year, that must be eliminated to meet the statutory mandate of section 110(a)(2)(D)(i)(I). Moreover, the structure of the program, which achieves required emission reductions through limits on the total number of allowances allocated, assurance provisions, and penalty mechanisms, ensures that the variability limits only allow the amount of temporal and geographic shifting of emissions that is likely to result from the inherent variability in power generation, and not from decisions to avoid or delay the installation of necessary controls. Under the remedy, an individual state can have emissions up to its budget plus the variability limit. However, the requirement that all sources hold allowances covering emissions, and the fact that those allowances are allocated based on state-specific budgets *without* variability, ensure that the total emissions from the states do not exceed the sum of the state budgets. The remedy, therefore, ensures both that total emissions do not exceed the total of the state budgets and that the required emission reductions occur in each state."

[175] 531 F.3d at 908.

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5. Compliance Deadlines

As discussed in sections II.A., III.B., and IV.A., the rule requires sources to comply with the new and revised NO_X emission budgets for the 2017 ozone season (May 1 through September 30) in order to ensure that necessary NO_X emissions reductions are made as expeditiously as practicable to assist downwind states' attainment and maintenance of the 2008 ozone NAAQS. The compliance deadline is coordinated with the attainment deadline for that standard and the rule includes provisions to ensure that all necessary reductions occur at sources within each individual state. Thus, under the new CSAPR NO_X Ozone Season Group 2 Trading Program established by this rule at subpart EEEEE of 40 CFR part 97, the first control period is the 2017 ozone season (*i.e.,* May 1, 2017 through September 30, 2017).

The deadline by which sources must hold Group 2 allowances in their compliance accounts at least equal to their emissions during the control period is March 1 of the year following the control period, which is the same as the deadline for holding allowances under the CSAPR annual trading programs. This is a change from the current CSAPR NO_X Ozone Season Trading Program provisions, which set a deadline of December 1 of the year of the control period, and is intended to simplify compliance and program administration and thereby reduce costs for both regulated parties and the EPA. Under these coordinated deadlines, the date by which Group 2 sources will be required to hold Group 2 allowances for compliance for purposes of the 2017 control period is March 1, 2018.

6. Monitoring and Reporting and the Allowance Management System

Monitoring and reporting in accordance with the provisions of 40 CFR part 75 are required for all units subject to the CSAPR NO_X ozone season trading programs and for all units covered under this final rule for the 2008 ozone NAAQS requirements. The EPA finalizes that the monitoring system certification deadline by which monitors are installed and certified for compliance use generally will be May 1, 2017, the beginning of the first control period in this rule, with potentially later deadlines for units that commence commercial operation less than 180 days before that date. Similarly, the EPA is finalizing that the first period in which emission reporting is required would be the quarter that includes May 1, 2017 (the second quarter of the year that covers April, May, and June). These monitoring and reporting deadlines are analogous to the current deadlines under the original CSAPR.

Under part 75, a unit has several options for monitoring and reporting, including the use of a CEMS; an excepted monitoring methodology based in part on fuel-flow metering for certain gas- or oil-fired peaking units; low-mass emissions monitoring for certain non-coal-fired, low emitting units; or an alternative monitoring system approved by the Administrator through a petition process. In addition, sources can submit petitions to the Administrator for alternatives to specific CSAPR and part 75 monitoring, recordkeeping, and reporting requirements. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits (RATAs) and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied and result in a conservative estimate of emissions for the period involved.

Further, part 75 requires electronic submission of a quarterly emissions report to the Administrator, in a format prescribed by the Administrator. The report will contain all of the data required concerning ozone season NO_X emissions.

Units currently subject to CSAPR NO_X ozone season or CSAPR NO_X annual trading program requirements monitor and report NO_X emissions in accordance with part 75, so most sources will not have to make any changes to monitoring and reporting practices. In fact, only units in Kansas, which are currently subject to the CSAPR NO_X annual trading program but not the CSAPR NO_X ozone season trading program, will need to start newly reporting ozone season NO_X mass emissions. These emissions are already measured under the annual program, so the change will be a minor reporting modification and the sources will not be required to install new monitoring systems. Units in the following states monitor and report NO_X emissions under the CSAPR NO_X ozone season trading program and will continue to do so without change under the CSAPR ozone update for the 2008 NAAQS: Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

7. Recordation of Allowances

The EPA is establishing deadlines for recording allocations of ozone season NO_X allowances to sources affected under this rule that generally parallel the recordation deadlines under the existing CSAPR trading programs, but with later deadlines reflecting the fact that this program is starting two years later than the existing CSAPR trading programs. Specifically, allocations to existing units for the first two control periods under the new program (2017 and 2018) will be recorded by January 9, 2017. This recordation deadline is four months before the start of the first control period for the new program (May 1, 2017) and 14 months before the date by which sources are required to hold allowances sufficient to cover their emissions for that first control period (March 1, 2018, as discussed previously), giving sources ample time to engage in allowance trading activities consistent with their preferred compliance strategies. Allowance allocations for 2019 and 2020 will be recorded by July 1, 2018; allocations for 2021 and 2022 will be recorded by July 1, 2019; and allocations for 2023 and 2024 will be recorded by July 1, 2020. Allowances for each succeeding control period will be recorded by July 1 of the fourth year before the year of the control period, matching the recordation schedule for the existing CSAPR trading programs. These deadlines apply to recordation of both allocations based on the default allocation provisions under 40 CFR 97.811 and 97.812 and allocations provided by states pursuant to approved SIP revisions. As under the CSAPR annual programs, allocations to new units from the NUSAs and Indian country NUSAs are made in two rounds, with first-round allocations recorded by August 1 of the year of the control period and second-round allocations recorded by February 15 of the year after the year of the control period. (In a change from the current CSAPR NO_X Ozone Season Trading Program provisions, the second-round recordation deadline is now coordinated with the analogous deadline for the CSAPR annual programs.) For 2018 allocations, the EPA will defer recordation if a state submits a timely letter indicating an intent to submit a SIP revision that if approved would substitute state-determined allocations for the default allocations determined by the EPA. The recordation provisions for the new program are codified in 40 CFR 97.821.

Consistent with the first recordation deadline described previously for allocations to existing units under the new trading program, the EPA is also delaying the deadline in 40 CFR 97.521(c) for recordation of allowances

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for the 2017 and 2018 control periods under the existing NO_X ozone season trading program (*i.e.,* allocations for sources in Georgia) to January 9, 2017. As explained in the proposal, the reason for extending this deadline was to avoid the possible need to take back allowances recorded under the existing NO_X ozone season trading program in cases where state budgets might have been reduced under that program by this final rule.

F. Submitting a SIP

Any state may replace the FIP finalized in this rule with a SIP at any time if approved by the EPA. ''Abbreviated'' and ''full'' SIP options finalized in the original CSAPR rulemaking continue to be available. An abbreviated SIP allows a state to submit a SIP that would provide for state-based allocation provisions in the CSAPR NO_X ozone season trading program that are then incorporated into the FIP the EPA has established for that state. A second approach, referred to as a full SIP, allows a state to adopt state provisions that would require sources in the state to continue to use the EPA-administered CSAPR trading program through an approved SIP, rather than a FIP. In addition to the abbreviated and full SIP options, as under the original CSAPR rulemaking, the EPA provides states with an opportunity to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2018 control period—through streamlined SIP revisions. *See* 76 FR 48208 at 48326–48332 (August 8, 2011) for additional discussion on full and abbreviated SIP options and 40 CFR 52.38(b). Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness. The EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51, appendix V.

1. 2018 SIP Option

The EPA will allow a state to submit a SIP revision establishing allowance allocations for existing units for the second compliance year (2018) for the new and revised budgets in order to replace the FIP-based allocations finalized in this rule. The process will be the same as under the original CSAPR rulemaking with deadlines shifted roughly 2 years: A state that wishes to take advantage of this option must submit a letter to EPA by December 27, 2016, indicating its intent to submit a complete SIP revision by April 1, 2017. The SIP must provide in an EPA-prescribed format a list of existing units and their allocations for the 2018 control period. If a state does not submit a letter of intent to submit a SIP revision, FIP allocations will be recorded by January 9, 2017. If a state submits a timely letter of intent but fails to submit a SIP revision, FIP allocations will be recorded by April 15, 2017. If a state submits a timely letter of intent followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by October 1, 2017.

2. 2019 and Beyond SIP Option

For the 2019 control period and later, the EPA is finalizing revisions to the regulations at 40 CFR 52.38(b) that provide additional options to submit abbreviated or full SIP revisions to modify or replace the FIP allowance allocations in 2019 or later years. The deadline for SIP submittals to modify or replace the FIP allocations for 2019 and 2020 is December 1, 2017. The deadline for the state to then submit state allocations for 2019 and 2020 is June 1, 2018 and the deadline for the EPA to record those allocations is July 1, 2018. A state may submit by December 1, 2018, a SIP revision applicable to control periods starting in 2021 or 2022, with state allocations due June 1, 2019, and allocation recordation by July 1, 2019. *See* section IV of this preamble and 76 FR 48208 at 48326–48332 (August 8, 2011) for additional discussion on full and abbreviated SIP options and 40 CFR 52.38(b).

3. SIP Revisions That Do Not Use the CSAPR Trading Program

Each state has the authority under the CAA to replace the FIP finalized in this rule by submitting a transport SIP revision that does not use the CSAPR NO_X ozone season trading program. The EPA will evaluate such SIPs to determine whether they include adequate and enforceable provisions ensuring that the emission reductions will be achieved based on the particular control strategies selected by each state. The SIP revision could include the following general elements: (1) A comprehensive baseline statewide NO_X emission inventory (which includes growth and existing control requirements); (2) a list and description of control measures to satisfy the state emission reduction obligation and a demonstration showing when each measure will be in place by the time the SIP is approved and replaces the CSAPR FIP; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe and large boilers and combustion turbines with a rated heat input capacity of 250 mmBtu per hour or greater, Part 75 monitoring, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP; and (5) a projected inventory demonstrating that state measures along with federal measures will achieve the necessary emission reductions in a timely manner considering ozone NAAQS attainment dates.[176] The SIPs must meet the requirements for public hearing, be adopted by the appropriate board or authority, and establish by a practically enforceable regulation a permit schedule and date for each affected source or source category to achieve compliance. For further information on replacing a FIP with a SIP, see the discussion in the final CSAPR rulemaking (76 FR 48326, August 8, 2011).

4. Submitting a SIP To Participate in CSAPR for States Not Included in This Rule

There could be circumstances where a state that is not obligated to reduce NO_X emissions in order to address interstate transport requirements (such as Florida, North Carolina, or South Carolina for purposes of this final rule) may wish to participate in the CSAPR NO_X ozone season trading program in order to serve a different regulatory purpose. For example, the state may have a pending request for redesignation of an area to attainment that relies on participation in the trading program as part of the state's demonstration that emissions will not exceed certain levels; or the state may wish to rely on participation in the trading program for purposes of a SIP revision to satisfy certain obligations under the Regional Haze Rule. Further, as discussed previously, Georgia may wish to join the CSAPR NO_X ozone season Group 2 trading program in order to trade with other Group 2 states.

The EPA took comment on whether the EPA should revise the CSAPR regulations to allow the EPA to approve a SIP revision in which a state seeks to participate in the NO_X ozone season trading program for a purpose other than addressing ozone transport obligations.

The EPA is finalizing revisions to CSAPR regulations to allow Georgia to opt-in to the CSAPR NO_X ozone season Group 2 trading group if it adopts, as part of a SIP revision, a NO_X ozone season emission budget no higher than the emission budget that reflects EGU NO_X mitigation strategies represented by a uniform cost of $1,400 per ton for EGUs in Georgia. Such an emission

[176] The EPA notes that the SIP is not required to include modeling.

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budget is provided by this final rule. As discussed previously, Georgia submitted comments indicating an interest in allowing its sources to trade with other states, although without any change to its budget. The EPA has already discussed the reasons for rejecting the specific option most favored by Georgia in comments. By providing Georgia with the option to bring the state's sources into the Group 2 program through a SIP revision, the EPA is allowing Georgia to implement its expressed preference for broader trading if that preference continues to apply even when conditioned on adoption of a more stringent budget.

The EPA also took comment on whether the EPA should revise the CSAPR regulations to allow the EPA to approve a SIP revision in which a state seeks to participate in the NO_X ozone season trading program for a purpose other than addressing ozone transport obligations. The EPA received no comments indicating that states had an interest in this option at this time, and the EPA is therefore not finalizing this option at this time.

G. Title V Permitting

This rule, like CSAPR, does not establish any permitting requirements independent of those under title V of the CAA and the regulations implementing title V, 40 CFR parts 70 and 71.[177] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with the applicable requirements of the CAA, including the requirements of the applicable State Implementation Plan. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this transport rule and given that many of the units covered here are already subject to CSAPR, most of the sources at which the units are located are already subject to title V permitting requirements. For sources subject to title V, the interstate transport requirements for the 2008 ozone NAAQS that are applicable to them under the final FIPs are ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the assurance provisions, and liability are ''applicable requirements'' that must be addressed in the permits.

Title V of the CAA establishes the basic requirements for state title V permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established by CSAPR and updated by this ozone interstate transport rule. 42 U.S.C. 7661a(b).

In CSAPR, the EPA established standard requirements governing how sources covered by the rule would comply with title V and its regulations.[178] 40 CFR 97.506(d). Under this rule, those same requirements would continue to apply to sources already in the CSAPR NO_X ozone season trading program and to any newly affected sources that have been added to address interstate transport of the 2008 ozone NAAQS. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.806(d)(1). This provision is also included in each title V permit for an affected source. This final rule maintains the approach taken under CSAPR that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this final rule also continues to support the means by which sources in the CSAPR NO_X ozone season trading program can use the title V minor modification procedure to change their approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR (*i.e.,* approaches using a continuous emission monitoring system, an excepted monitoring system under appendices D and E to part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.806(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). As described in the EPA's 2015 guidance, the agency suggests in its template that sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under the rule, and the applicable requirements governing each of those approaches. Inclusion of the table in a source's title V permit therefore allows a covered unit that seeks to change or add to their chosen monitoring and recordkeeping approach to easily comply with the regulations governing the use of the title V minor modification procedure.

Under CSAPR, in order to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. The EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on the EPA's Web site.[179] The EPA maintains the same approach in this final rule.

Consistent with the EPA's approach under CSAPR, the applicable requirements resulting from these FIPs must be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 40 CFR 71.7(f)) or the standard permit renewal provisions (40 CFR 70.7(c) and

[177] Part 70 addresses requirements for state title V programs, and Part 71 governs the federal title V program.

[178] The EPA also issued a guidance document and template that includes instructions describing how to incorporate the CSAPR applicable requirements into a source's title V permit. *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_Title_V_Permit_Guidance.pdf.*

[179] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

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71.7(c)).[180] For sources newly subject to title V that are affected sources under the final FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As in CSAPR, the approach to title V permitting under the FIPs imposes no independent permitting requirements and should reduce the burden on sources already required to be permitted under title V and on permitting authorities.

H. Relationship to Other Emission Trading and Ozone Transport Programs

1. Interactions With Existing CSAPR Annual Programs, Title IV Acid Rain Program, NO_X SIP Call, and Other State Implementation Plans

a. *CSAPR Annual Programs.*[181] Nothing in this rule affects any CSAPR NO_X annual or CSAPR SO_2 Group 1 or CSAPR SO_2 Group 2 requirements.[182] The CSAPR annual program requirements were premised on the 1997 and 2006 $PM_{2.5}$ NAAQS that are not being addressed in this rulemaking. The CSAPR NO_X annual trading program and the CSAPR SO_2 Group 1 and Group 2 trading programs remain in place and will continue to be administered by the EPA.

The EPA acknowledges that, in addition to the ozone budgets discussed previously, the D.C. Circuit has remanded for reconsideration the CSAPR SO_2 budgets for Alabama, Georgia, South Carolina, and Texas. *EME Homer City II,* 795 F.3d at 138. This rule does not address the remand of these CSAPR phase 2 SO_2 emission budgets. On June 27, 2016, the EPA released a memorandum outlining the agency's approach for responding to the D.C. Circuit's July 2015 remand of the CSAPR phase 2 SO_2 annual emission budgets for Alabama, Georgia, South Carolina and Texas. The memorandum can be found at *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf*.

b. *Title IV Interactions.* This rule will not affect any Acid Rain Program requirements. Acid Rain Program SO_2 and NO_X requirements are established in Title IV of the Clean Air Act, and will continue to apply independently of this rule's provisions. Any Title IV sources that are subject to provisions of this rule are still required to comply with Title IV requirements, including the requirement to hold Title IV allowances to cover SO_2 emissions at the end of a compliance year.

c. *NO_X SIP Call Interactions.* States subject to both the NO_X SIP Call and the final CSAPR Update will be required to comply with the requirements of both rules. The final CSAPR Update rule requires NO_X ozone season emission reductions from EGUs greater than 25 MW in most NO_X SIP Call states and at levels greater than required by the NO_X SIP Call. Therefore, compliance with the budgets established under the CSAPR Update would satisfy the requirements of the NO_X SIP Call for these large EGU units.

The NO_X SIP Call states used the NO_X Budget Trading Program (NBP) model rule to comply with the NO_X SIP Call requirements for EGUs serving a generator with a nameplate capacity greater than 25 MW and large non-EGUs with a maximum rated heat input capacity greater than 250 mmBTU/hr. (In some states, EGUs smaller than 25 MW were also part of the NBP as a carryover from the Ozone Transport Commission NO_X Budget Trading Program.) When the EPA promulgated CAIR and the CAIR FIPs, it allowed states, via SIP, to adopt SIP revisions modifying the applicability provisions of the CAIR NO_X Ozone Season Trading Program to include all NO_X Budget Trading Program units in that program as a way to continue to meet the requirements of the NO_X SIP Call for these sources.

In CSAPR, however, the EPA allowed states, via SIP, to expand applicability of the trading program to EGUs smaller than 25 MW but did not allow the expansion of applicability to include large non-EGU sources. The EPA explained that the reason for excluding large non-EGU sources was based on a concern that emissions from these sources were generally much lower than the portion of each state's NO_X SIP Call budget amount attributable to these large non-EGUs, and we were therefore concerned that surplus allowances created as a result of an overestimation of baseline emissions (the main basis for the non-EGU portion of the NO_X Budget Trading Program budget) and subsequent shutdowns of these large non-EGUs (since 1999 when the NO_X SIP Call was promulgated) would prevent needed reductions by the EGUs to address significant contribution to downwind air quality impacts. *See* 76 FR 48323 (August 8, 2011).

Since then, states have had to find appropriate ways to ensure that their rules continue to show compliance with emissions reduction obligations of the NO_X SIP Call, particularly for large non-EGUs.[183] Most states that used the CAIR NO_X Ozone Season Trading Program as a means of complying with the NO_X SIP Call obligations for large non-EGUs are still working to find suitable solutions now that CSAPR has replaced CAIR.[184]

Therefore, the EPA is finalizing provisions to allow any NO_X SIP Call state subject to a FIP promulgated by this rule to voluntarily submit a SIP revision with a revised budget level that is environmentally neutral to address the state's NO_X SIP Call requirement for ozone season NO_X reductions. The SIP revision could include a provision to expand the applicability of the CSAPR NO_X ozone season trading program in that state to include all NO_X Budget Trading Program units, including large non-EGUs. Analysis shows that these units (mainly large non-EGU boilers, combustion turbines, and combined cycle units with a maximum rated heat input capacity greater than 250 mmBtu/hr) continue to emit well below their portion of the NO_X SIP Call budget. In order to ensure that the necessary amount of EGU emission reductions occur for purposes of addressing interstate transport with respect to the 2008 ozone NAAQS in covered states that submit such a SIP revision, the corresponding state ozone season emission budget amount could be increased by no more than the lesser of the highest ozone season NO_X emissions in the last 3 years from those units or the portion of the NO_X Budget Trading Program Budget attributable to large non-EGUs.[185] The environmental

[180] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(I) and 71.7(f)(1)(I).

[181] Reflecting the nomenclature updates adopted in this rule, the CSAPR Annual Programs are referred to in regulations as the CSAPR NO_X Annual Trading Program (40 CFR 97.401–97.435), the CSAPR SO_2 Group 1 Trading Program (40 CFR 97.601–97.635) and the CSAPR SO_2 Group 2 Trading Program (40 CFR 97.701–97.735). (Prior to this rule, the regulations used the acronym ''TR'' instead of the acronym ''CSAPR''.)

[182] As discussed in section IX in this preamble, the EPA is making technical corrections to the regulations concerning CSAPR's annual programs, but these corrections do not substantively alter any existing requirements.

[183] Compliance with CSAPR by the EGUs in a state will generally ensure that aggregate emissions from the state's EGUs will not exceed the amount of the state's NO_X SIP Call budget for the source category because the CSAPR cap is lower than the EGU portion of the NO_X SIP Call emission levels.

[184] Affected sources continue to report ozone season emissions using part 75 as required by the NO_X SIP Call and reported emissions have been below NO_X SIP Call non-EGU budget levels.

[185] For further information regarding the determination of the maximum amounts of additional allowances that could be issued by these states, see the memo entitled ''Maximum amounts of additional ozone season NO_X allowances that may be issued under SIP revisions expanding

Continued

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impact would be neutral using this approach. This approach addresses requests by states for help in determining an appropriate way to address the continuing NO_X SIP Call requirement as to non-EGU sources.

The variability limits established for EGUs remain unchanged as a result of including these non-EGUs. The assurance provisions apply to EGUs, and emissions from non-EGUs would not affect the assurance levels. The provisions of the new Group 2 trading program exclude the emissions and allowance allocations of any non-EGUs participating in the program from any determination of whether a state exceeds its assurance level or whether any group of sources exceeds its share of the responsibility for any exceedance of a state's assurance level. Similarly, the provisions limit the total allocations that can be taken into account for such purposes by all the EGUs in the state to the state budget and thereby prevent any additional allowances issued by the state as a result of expanded program applicability from unduly influencing determinations of shares of responsibility for any exceedance of the state's assurance level. For additional discussion of the specific regulatory provisions involved, see section IX of this preamble.

The NO_X SIP Call generally requires that states choosing to rely on large EGUs and large non-EGUs for meeting NO_X SIP Call emission reduction requirements must establish a NO_X mass emissions cap on each source and require part 75, subpart H monitoring. As an alternative to source-by-source NO_X mass emission caps, a state may impose NO_X emission rate limits on each source and use maximum operating capacity for estimating NO_X mass emissions or may rely on other requirements that the state demonstrates to be equivalent to either the NO_X mass emission caps or the NO_X emission rate limits that assume maximum operating capacity. Collectively, the caps or their alternatives cannot exceed the portion of the state budget for those sources. *See* 40 CFR 51.121(f)(2) and (i)(4). If a state chooses to expand the applicability of the CSAPR NO_X ozone season trading program to other sources in the state through a voluntary SIP revision to include all the NO_X Budget Trading Program units in the CSAPR NO_X ozone season trading program, the cap requirement would be met through the new budget and the monitoring requirement would be met through the trading program provisions, which require part 75 monitoring. The EPA will work with states to ensure that NO_X SIP Call obligations continue to be met.

d. Other State Implementation Plans. The EPA has not conducted any technical analysis to determine whether compliance with this rule will satisfy other requirements for EGUs in any attainment or nonattainment areas (*e.g.,* RACT or BART). For that reason, the EPA is not making determinations nor establishing any presumptions that compliance with the final rule satisfies any other requirements for EGUs. Based on analyses that states conduct on a case-by-case basis, states may be able to conclude that compliance with the rule for certain EGUs fulfills other SIP requirements. The EPA encourages states to work with their regional office on these issues.

2. Other Federal Rulemakings

a. *Clean Power Plan.* On August 3, 2015, the EPA finalized the Clean Power Plan (CPP).[186] The Clean Air Act—under section 111(d)—creates a partnership between the EPA, states, tribes and U.S. territories—with the EPA setting a goal and states and tribes choosing how they will meet it. The CPP follows that approach. The CPP establishes interim and final CO_2 emission performance rates for certain existing power plants, under CAA section 111(d). States then develop and implement plans that ensure that the affected power plants in their state—either individually, together, or in combination with other measures—achieve these rates or equivalent state rate- or mass-based goals. The CPP includes interim emission performance rates (or equivalent state goals) to be achieved over the years 2022 to 2029 and the final CO_2 emission performance rates (or equivalent state goals) to be achieved in 2030 and after.

On February 9, 2016, the Supreme Court granted applications to stay the Clean Power Plan, pending judicial review of the rule in the D.C. Circuit, including any subsequent review by the Supreme Court.[187] The EPA firmly believes the Clean Power Plan will be upheld when the courts address its merits because the Clean Power Plan rests on strong scientific and legal foundations. The stay means that no one has to comply with the Clean Power Plan while the stay is in effect. During the pendency of the stay, states are not required to submit plans to EPA, and EPA will not take any action to impose or enforce any such obligations. The Supreme Court's orders granting the stay did not discuss the parties' differing views of whether and how the stay would affect the CPP's compliance deadlines, and they did not expressly resolve that issue. In this context, the question of whether and to what extent tolling is appropriate will need to be resolved once the validity of the CPP is finally adjudicated.

Because mandatory emission reductions under the CPP would not begin until several years after the 2017 implementation of the CSAPR Update rule, the EPA does not anticipate significant interactions with the CPP and the near-term (*i.e.,* starting in 2017) ozone season EGU NO_X emission reduction requirements under this rule. *See* section V.B of the preamble for further information on this point. However the EPA notes that actions taken to reduce CO_2 emissions (*e.g.,* deployment of zero-emitting generation) may also reduce ozone season NO_X emissions. The EPA is also cognizant of the potential influence of addressing interstate ozone transport on CO_2 emissions. As states and utilities undertake the near- and longer-term planning to reduce emissions of these pollutants, they will have the opportunity to consider how compliance with this rule can anticipate, or be consistent with, greenhouse gas mitigation. Some EGU NO_X mitigation strategies, most notably shifting generation from higher NO_X-emitting coal-fired units to existing low NO_X-emitting units or zero-emitting units, can potentially also reduce CO_2 emissions. As the EPA has structured the interstate transport obligations that would be established by this rule as requirements to limit aggregate affected EGU emissions and the EPA is not enforcing source-specific emission reduction requirements, EGU owners have the flexibility to plan for compliance with the interstate ozone transport requirements in ways that are consistent with state and EGU strategies to reduce CO_2 emissions.

b. *2015 Ozone Standard.* On October 1, 2015, the EPA strengthened the ground-level ozone NAAQS to 70 ppb, based on extensive scientific evidence about ozone's effects on public health and welfare.[188] This rule updating the CSAPR NO_X ozone season trading program to address interstate emission transport with respect to the 2008 ozone NAAQS is a separate and distinct regulatory action and is not meant to address the CAA's good neighbor

CSAPR trading program applicability to large non-EGUs'', available in the docket.

[186] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 FR 64661 (Oct. 23, 2015).

[187] *West Virginia et al.* v. *EPA*, No. 15A773 (U.S. Feb. 9, 2016).

[188] 80 FR 65291 (October 26, 2015).

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provision with respect to the strengthened 2015 ozone NAAQS.

The EPA is mindful of the need to address ozone transport for the 2015 ozone NAAQS. The statutory deadline for the EPA to finalize area designations is October 1, 2017. Further, good neighbor SIPs from states are due on October 1, 2018. The steps taken under this rule to reduce interstate ozone transport will help states make progress toward attaining and maintaining the 2015 ozone NAAQS. Moreover, to facilitate the implementation of the CAA good neighbor provision with respect to the 2015 ozone NAAQS, the EPA intends to provide additional information regarding steps 1 and 2 of the CSAPR framework in the fall of 2016. In particular, the EPA expects to conduct and release modeling necessary to assist states to identify projected nonattainment and maintenance receptors with respect to the 2015 ozone NAAQS and identify the upwind state emissions that contribute significantly to these receptors.

VIII. Costs, Benefits, and Other Impacts of the Final Rule

The EPA evaluated the costs, benefits, and impacts of compliance with the final EGU NO_X ozone season emission budgets developed using uniform control stringency represented by $1,400 per ton. In addition, the EPA also assessed compliance with one more and one less stringent alternative EGU NO_X ozone season emission budgets, developed using uniform control stringency represented by $3,400 per ton and $800 per ton, respectively. The EPA evaluated the impact of implementing these emission budgets to reduce interstate transport for the 2008 ozone NAAQS in 2017. More details for this assessment can be found in the Regulatory Impact Analysis (RIA) in the docket for this final rule.

The EPA notes that its analysis of the regulatory control alternatives (*i.e.,* the final rule and more and less stringent alternatives) is illustrative in nature, in part because the EPA will implement the EGU NO_X emission budgets via a regional NO_X ozone season allowance trading program. This implementation approach provides utilities with the flexibility to determine their own compliance path. The EPA's assessment develops and analyzes one possible scenario for implementing the NO_X budgets finalized by this action and one possible scenario for implementing the more and less stringent alternatives. Furthermore, the emission budgets evaluated for the CSAPR Update regulatory control alternative in this benefit and cost analysis are illustrative because they differ somewhat from the budgets finalized in this rule. (The budgets for the more and less stringent alternative also differ somewhat from the budgets represented by $3,400 per ton and $800 per ton reported in Table VI.C–1). However, the RIA also reports the costs and emissions changes associated with the finalized budgets. Further details on the illustrative nature of this analysis can be found in the RIA in the docket for this rule.

For this final rule, the EPA analyzed the costs to the electric power sector and emissions changes using IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies throughout the contiguous United States for the entire power system. Documentation for IPM can be found in the docket for this rulemaking or at *www.epa.gov/powersectormodeling*.

Table VIII.1 provides the projected 2017 EGU emissions reductions for the evaluated regulatory control alternatives.

TABLE VIII.1—PROJECTED 2017 EMISSIONS REDUCTIONS OF NO_X AND CO_2 WITH THE FINAL NO_X EMISSION BUDGETS AND MORE OR LESS STRINGENT ALTERNATIVES

[Tons] [1][2]

	Final rule	More stringent alternative	Less stringent alternative
NO_X (annual)	¥75,000	¥79,000	¥27,000
NO_X (ozone season)	¥61,000	¥66,000	¥27,000
CO_2 (annual)	¥1,600,000	¥2,000,000	¥1,300,000

[1] NO_X emissions are reported in English (short) tons; CO_2 is reported in metric tons.

[2] All estimates are rounded to two significant figures.

The EPA estimates the costs associated with compliance with the illustrative regulatory control alternative for the final CSAPR Update to be approximately $68 million annually. These costs represent the private compliance cost of reducing NO_X emissions to comply with the final rule and does not include monitoring, recordkeeping, and reporting costs. Table VIII.2 provides the estimated costs for the evaluated regulatory control scenarios, including the final rule and more and less stringent alternatives. Estimates are in 2011 dollars.

TABLE VIII.2—COST ESTIMATES FOR COMPLIANCE WITH THE FINAL RULE NO_X EMISSION BUDGETS AND MORE AND LESS STRINGENT ALTERNATIVES

[2011$] [1][2]

	Final rule	More stringent alternative	Less stringent alternative
Costs	68,000,000	82,000,000	8,000,000

[1] Costs are annualized over the period 2017 through 2020 using the 4.77 discount rate used in IPM's objective function of minimizing the net present value of the stream of total costs of electricity generation. These costs do not include monitoring, recordkeeping, and reporting costs, which are reported separately. See Chapter 4 of the RIA for this final rule for details and explanation.

[2] All estimates are rounded to two significant figures.

In this analysis, the EPA monetized the estimated benefits associated with reducing population exposure to ozone and $PM_{2.5}$ from reductions in NO_X emissions and co-benefits of decreased emissions of CO_2, but was unable to

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quantify or monetize the potential co-benefits associated with reducing exposure to NO_2 as well as ecosystem effects and reduced visibility impairment from reducing NO_X emissions. Among the benefits it could quantify, the EPA estimated combinations of health benefits at discount rates of 3 percent and 7 percent (as recommended by the EPA's *Guidelines for Preparing Economic Analyses* [U.S. EPA, 2014] and OMB's *Circular A–4* [OMB, 2003]) and climate co-benefits of CO_2 reductions at discount rates of 5 percent, 3 percent, 2.5 percent, and 3 percent (95th percentile) (as recommended by the interagency working group). The EPA estimates the monetized ozone-related benefits [189] of the final rule to be $370 million to $610 million (2011$) in 2017 and the $PM_{2.5}$-related co-benefits [190] of the final rule to be $93 million to $210 million (2011$) using a 3 percent discount rate and $83 million to $190 million (2011$) using a 7 percent discount rate. Further, the EPA estimates CO_2-related co-benefits of $54 to $87 million (2011$). Additional details on this analysis are provided in the RIA for this final rule. Tables VIII.3 and VIII.5 summarize the quantified monetized human health and climate benefits of the rule and the more and less stringent control alternatives. Table VIII.4 summarizes the estimated avoided ozone- and $PM_{2.5}$-related health incidences for the final rule and the more and less stringent control alternatives.

TABLE VIII.3—ESTIMATED HEALTH BENEFITS OF PROJECTED 2017 EMISSIONS REDUCTIONS FOR THE FINAL RULE, AND MORE OR LESS STRINGENT ALTERNATIVES

[Millions of 2011$] [1,2]

	Final rule	More stringent alternative	Less stringent alternative
NO_X (as ozone)	$370 to $610	$400 to $650	$160 to $270
NO_X (as $PM_{2.5}$)	$93 to $210	$98 to $220	$34 to $75
3% Discount Rate	$83 to $190	$88 to $200	$30 to $67
7% Discount Rate			
Total:			
3% Discount Rate	$460 to $810	$500 to $870	$200 to $340
7% Discount Rate	$450 to $790	$490 to $850	$190 to $330

[1] The health benefits range is based on adult mortality functions (*e.g.*, from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Zanobetti and Schwartz (2008)).
[2] All estimates are rounded to two significant figures.

TABLE VIII.4—SUMMARY OF ESTIMATED AVOIDED OZONE-RELATED AND $PM_{2.5}$-RELATED HEALTH INCIDENCES FROM PROJECTED 2017 EMISSIONS REDUCTIONS FOR THE FINAL RULE AND MORE OR LESS STRINGENT ALTERNATIVES [1]

	Final rule	More stringent alternative	Less stringent alternative
Ozone-Related Health Effects			
Avoided Premature Mortality:			
Smith *et al.* (2009) (all ages)	21	23	9
Zanobetti and Schwartz (2008) (all ages)	60	65	26
Avoided Morbidity:			
Hospital admissions—respiratory causes (ages >65)	59	64	26
Emergency room visits for asthma (all ages)	240	250	100
Asthma exacerbation (ages 6–18)	67,000	73,000	30,000
Minor restricted-activity days (ages 18–65)	170,000	180,000	75,000
School loss days (ages 5–17)	56,000	60,000	25,000
$PM_{2.5}$-Related Health Effects			
Avoided Premature Mortality:			
Krewski *et al.* (2009) (adult)	10	11	3.7
Lepeule *et al.* (2012) (adult)	23	25	8.4
Woodruff *et al.* (1997) (infant)	<1	<1	<1
Avoided Morbidity:			
Emergency department visits for asthma (all ages)	6.1	6.5	2.2
Acute bronchitis (age 8–12)	15	15	5.2
Lower respiratory symptoms (age 7–14)	180	190	67
Upper respiratory symptoms (asthmatics age 9–11)	260	280	95
Minor restricted-activity days (age 18–65)	7,500	7,900	2,700
Lost work days (age 18–65)	1,300	1,300	450
Asthma exacerbation (age 6–18)	270	290	98
Hospital admissions—respiratory (all ages)	2.8	2.9	1.0
Hospital admissions—cardiovascular (age >18)	3.8	4.0	1.4
Non-Fatal Heart Attacks (age >18)			

[189] The ozone-related health benefits range is based on applying different adult mortality functions (*i.e.*, Smith et al. (2009) and Zanobetti and Schwartz (2008)).

[190] The $PM_{2.5}$-related health co-benefits range is based on applying different adult mortality functions (*i.e.*, Krewski et al. (2009) and Lepeule et al. (2012)).

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TABLE VIII.4—SUMMARY OF ESTIMATED AVOIDED OZONE-RELATED AND $PM_{2.5}$-RELATED HEALTH INCIDENCES FROM PROJECTED 2017 EMISSIONS REDUCTIONS FOR THE FINAL RULE AND MORE OR LESS STRINGENT ALTERNATIVES [1]—Continued

	Final rule	More stringent alternative	Less stringent alternative
Peters *et al.* (2001)	12	13	4.3
Pooled estimate of 4 studies	1.3	1.4	0.46

[1] All estimates are rounded to whole numbers with two significant figures.

TABLE VIII.5—ESTIMATED GLOBAL CLIMATE CO-BENEFITS OF CO_2 REDUCTIONS FOR THE FINAL RULE AND MORE OR LESS STRINGENT ALTERNATIVES

[Millions of 2011$] [1]

Discount rate and statistic	Final rule	More stringent alternative	Less stringent alternative
5% (average)	$19	$25	$15
3% (average)	66	87	54
2.5% (average)	100	130	81
3% (95th percentile)	190	250	150

[1] The social cost of carbon (SC–CO_2) values are dollar-year and emissions-year specific. SC–CO_2 values represent only a partial accounting of climate impacts.

The EPA combined this information to perform a benefit-cost analysis for this final rule (shown in table VIII.6 and for the more and less stringent alternatives—shown in the RIA in the docket for this rule).

TABLE VIII.6—TOTAL COSTS, TOTAL MONETIZED BENEFITS, AND NET BENEFITS OF THE FINAL RULE IN 2017 FOR U.S.

[Millions of 2011$] [1]

Climate Co-Benefits	$66
Air Quality Health Benefits	$460 to $810 [2] and $450 to $790 [3]
Total Benefits	$530 to $880 [2] and $520 to $860 [3]
Annualized Compliance Costs	$68 [4]
Net Benefits	$460 to $810 [2] and $450 to $790 [3]
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2. Ecosystem benefits and visibility improvement assoc. with reductions in emissions of NO_X.

[1] All estimates are rounded to two significant figures.
[2] 3% discount rate.
[3] 7% discount rate.
[4] These costs do not include monitoring, recordkeeping, and reporting costs, which are reported separately. See Chapter 4 of the RIA for this final rule for details and explanation.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, the EPA's estimates of the co-benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include the potential co-benefits from reducing direct exposure to NO_X as well as from reducing ecosystem effects and visibility impairment by reducing NO_X emissions. Based upon the foregoing discussion, it remains clear that the benefits of this final action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in the RIA for this rule.

The EPA provides a qualitative assessment of economic impacts associated with electricity price changes to consumers that may result from this final rule. This assessment can be found in the RIA for this rule in the docket.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science'' (Executive Order 13563, 2011). Although benefit-cost analyses that are consistent with standard economic theory have not typically included a separate analysis of regulation-induced employment impacts, regulatory impact analyses prepared by the EPA do include analysis of employment impacts. Employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices as part of developing SIPs for compliance with the emission budgets found in this final rule. Given the wide range of approaches that may be used and industries that could be affected, quantifying the associated employment impacts is difficult. The EPA provides an analysis of employment impacts for the final rule in the RIA. The employment analysis includes quantitative estimation of employment changes related to installation and operation of new pollution control equipment, ongoing expenditures on pollution control, changes in electricity generation and fuel use, and qualitative discussion of employment trends both for the electric power sector and in related fuel markets for the illustrative CSAPR update alternative.

IX. Summary of Changes to the Regulatory Text for the CSAPR FIPs and CSAPR Trading Programs

This section describes amendments to the regulatory text in the CFR for the CSAPR FIPs and the CSAPR NO_X ozone season trading program related to the findings and remedy discussed throughout this preamble. This section also describes other minor corrections to the existing CFR text for the CSAPR FIPs and the CSAPR trading programs more generally.

As a preliminary matter, it is worth noting that two of the changes made from the proposal to the final rule after consideration of comments dramatically simplify the final regulatory text as compared to the proposed amendments. First, because the final rule does not allow post-2016 allowances issued to sources in Georgia to be used for compliance by sources in other states, the final regulatory text establishes a new, separate CSAPR NO_X Ozone Season Group 2 Trading Program in a new subpart EEEEE of part 97 for sources subject to this rule instead of including those sources in the existing trading program in subpart BBBBB of part 97 (which is renamed the CSAPR NO_X Ozone Season Group 1 Trading Program and will now apply only to sources in Georgia). Second, the final text addresses the use of banked 2015 and 2016 allowances to meet compliance obligations under this rule by providing for a one-time conversion of Group 1 allowances to Group 2 allowances instead of creating an ongoing process of ''tonnage equivalent'' determinations. These two simplifying changes largely eliminate the need for substantive amendments to the existing Group 1 trading program regulations other than to address the one-time conversion of the banked allowances, as discussed in section IX.B of this preamble. Although the changes do result in the creation of new subpart EEEEE of part 97, the provisions of the new subpart parallel the existing subpart BBBBB provisions with only a small number of exceptions.

A. Amendments to the CSAPR FIPs in Part 52

The CSAPR FIPs related to ozone season NO_X emissions are set forth in § 52.38(b) as well as CFR sections specific to each covered state. The principal amendments to those FIPs made by this rule appear in § 52.38(b)(1) and (2) as well as the state-specific CFR sections. The amendments to § 52.38(b)(1) expand the overall set of CSAPR trading programs addressing ozone season NO_X emissions to include the new Group 2 trading program in subpart EEEEE of part 97 in addition to the current Group 1 trading program in subpart BBBBB of part 97. The amendments to § 52.38(b)(2) identify the states whose sources are required under the FIPs to participate in each of the respective trading programs with regard to their emissions occurring in particular years. More specifically, § 52.38(b)(2)(ii) ends the requirement to participate in the Group 1 program after the 2016 control period for sources in all states whose sources currently participate in that program except Georgia, and §52.38(b)(2)(iii) establishes the requirement for the 22 states covered by this rule to participate in the Group 2 program starting with the 2017 control period. These changes in requirements are replicated, as applicable, in the state-specific CFR sections for the respective states.[191]

The options for states covered by this rule to modify or replace the FIPs implementing the emission reduction requirements under this rule are finalized substantially as proposed, but generally as new options to modify or replace subpart EEEEE requirements instead of as changes to the existing options to modify or replace subpart BBBBB requirements. Thus, new § 52.38(b)(7), (8), and (9) establish options to replace allowance allocations for the 2018 control period, to adopt an abbreviated SIP revision for control periods in 2019 or later years, and to adopt a full SIP revision for control periods in later years, respectively. These options generally replicate the analogous options in § 52.38(b) (3), (4) and (5) with regard to the subpart BBBBB program. To make use of the 2018 option, a state must notify the EPA by December 27, 2016 of its intent to submit to the EPA by April 1, 2017 a state-approved spreadsheet with allowance allocations to existing units. The submission deadline for an abbreviated or full SIP affecting 2019 or 2020 allocations is December 1, 2017.

The revised FIPs also clarify that in cases where a FIP represents a partial rather than full remedy for the state's obligation to address interstate air pollution, an approved SIP revision replacing that FIP would also be a partial rather than full remedy for that obligation, unless provided otherwise in the EPA's approval. (As discussed in section VI of this preamble, for all covered states except Tennessee, the emission reduction requirements established in this rule represent partial rather than full remedies to the respective states' interstate transport obligations with regard to the 2008 ozone NAAQS.)

The abbreviated and full SIP options under the Group 2 program do have one important difference from the similar options under the Group 1 program, namely that §52.38(b)(8)(ii) and (9)(ii) include an option for a state to expand applicability to include non-EGUs in the state that were previously subject to the NO_X Budget Trading Program. As discussed in section VII.F of this preamble, in conjunction with such an expansion, the state may also issue an additional amount of allowances. New § 52.38(b)(10)(ii) clarifies that a SIP revision requiring a state's sources—EGUs or non-EGUs—to participate in the Group 2 trading program would satisfy the state's obligations to adopt control measures for such sources under the NO_X SIP Call.

The option discussed in section VII.C.1 of this preamble for Georgia to replace the FIP requiring its sources to participate in the Group 1 program with a SIP revision requiring its sources to participate in the Group 2 program is set forth in § 52.38(b)(6). This option is generally similar to the full SIP option under § 52.38(b)(9) for states whose sources are already subject to the Group 2 program under a FIP. The provisions would allow Georgia to elect (subject to EPA approval) to allocate Group 2 allowances for future control periods under the SIP revision (even if the EPA had already commenced allocations of Group 1 allowances to Georgia sources for those control periods) instead of having the EPA convert the Group 1 allowances already allocated for future years into Group 2 allowances under § 97.526(c)(2), as described later on. Approval by the EPA of a Georgia SIP revision of this nature would also result in the conversion of all remaining Group 1 allowances banked from earlier control periods into Group 2 allowances under § 97.526(c)(3), as also described later on.

New § 52.38(b)(11)(ii) preserves the EPA's authority to carry out conversions of Group 1 allowances to Group 2

[191] *See* §§ 52.54(b) (Alabama), 52.184 (Arkansas), 52.540 (Florida), 52.731(b) (Illinois), 52.789(b) (Indiana), 52.840(b) (Iowa), 52.882(b) (Kansas), 52.940(b) (Kentucky, 52.984(d) (Louisiana), 52.1084(b) (Maryland), 52.1186(e) (Michigan), 52,1284 (Mississippi), 52.1326(b) (Missouri), 52.1584(e) (New Jersey), 52.1684(b) (New York), 52.1784(b) (North Carolina), 52.1882(b) (Ohio), 52.1930 (Oklahoma), 52.2040(b) (Pennsylvania), 52.2140(b) (South Carolina), 52.2240(e) (Tennessee), 52.2283(d) (Texas), 52.2440(b) (Virginia), 52.2540(b) (West Virginia), and 52.2587(e) (Wisconsin).

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allowances in all compliance accounts (as well as all general accounts) following any SIP revision that would otherwise lead to automatic withdrawal of a CSAPR FIP with regard to particular sources.

Finally, new § 52.38(b)(12) and (13), respectively, contain updatable lists of states with approved SIP revisions to modify or replace the CSAPR FIPs requiring participation in either the Group 1 program or the Group 2 program. Similar updatable lists for states with SIPs related to the NO_X Annual, SO_2 Group 1, and SO_2 Group 2 programs are added at new §§ 52.38(a)(8) and 52.39(l) and (m), respectively. With the addition of these updatable lists, all previously approved and future CSAPR SIP revisions will be acknowledged in centralized CFR locations and will no longer be acknowledged through amendments to the individual states' FIPs.[192]

B. Amendments to the Group 1 Trading Program Provisions in Subpart BBBBB of Part 97

As noted previously, the EPA's determinations regarding the separation of Georgia allowances and the one-time conversion of banked allowances dramatically simplify the amendments in the final rule compared to the proposed amendments. Most significantly, in place of the proposed amendments designed to implement the concept of ''tonnage equivalents,'' which would have affected multiple sections of the Group 1 regulations throughout subpart BBBBB, the final regulatory text implements the one-time conversion of banked Group 1 allowances to Group 2 allowances through amendments limited to the Group 1 trading program banking provisions in § 97.526. Specifically, new § 97.526(c)(1) sets forth the schedule and mechanics for a default one-time conversion of most Group 1 allowances that remain banked following the completion of deductions for compliance for the 2016 control period. The conversion will be applied to banked Group 1 allowances held in any general account and in any compliance account except a compliance account for a source located in Georgia. The owner or operator of a Georgia source can retain banked Group 1 allowances for future use in the Group 1 program simply by keeping the allowances in the source's compliance account as of the conversion date or, alternatively, can elect to have banked allowances converted to Group 2 allowances simply by transferring the allowances from the source's compliance account to a general account prior to the conversion date. The conversion factor is determined based on the ratio of the total number of banked Group 1 allowances being converted to 1.5 times the sum of the variability limits for all states covered by the Group 2 program.

Two additional conversion provisions in § 97.526(c)(2) and (3) apply only if Georgia submits and the EPA approves a SIP revision requiring sources in Georgia to participate in the Group 2 program. In that case, under § 97.526(c)(2) the EPA would replace the allocations of Group 1 allowances to Georgia sources already recorded for future control periods with allocations of Group 2 allowances, using a conversion factor determined based on the ratio of Georgia's emissions budget under the Group 1 program to its emissions budget under the Group 2 program. Under § 97.526(c)(3) the EPA would convert any remaining banked Group 1 allowances from prior control periods using a conversion factor based on the ratio of the total number of Group 1 allowances being converted to 1.5 times Georgia's variability limit under the Group 2 program. Allowances would be converted under these provisions regardless of the accounts in which they were held.

Additional provisions of § 97.526(c) address special circumstances. Under § 97.526(c)(4), if Group 1 allowances are removed for conversion from the compliance account for a source located in Florida, North Carolina, or South Carolina, the owner or operator can identify to the EPA a different account to receive the Group 2 allowances. This provision is necessary because sources in these states will not be participating in the Group 2 program, and Group 2 allowances cannot be recorded in any compliance account other than a compliance account for a source with a unit affected under the Group 2 program.

Under § 97.526(c)(5), the EPA may group multiple general accounts under common ownership for purposes of performing conversion computations. Because allowances are only recorded as whole allowances, allowance conversion computations will necessarily be rounded to whole allowances. The purpose of the grouping provision is to ensure that, given rounding, the total quantities of Group 2 allowances issued are not unduly affected by how the Group 1 allowances are distributed across multiple general accounts under common ownership, with potentially adverse consequences to achievement of the emission reductions required under the rule.

There is a possibility under the Group 1 program that some new Group 1 allowances could be issued after the conversions to Group 2 allowances have already taken place. Under § 97.526(c)(6), the EPA may convert these allowances to Group 2 allowances as if they had been issued and recorded before the general conversions.

Owners and operators of non-Georgia sources generally will not be able to retain banked Group 1 allowances (except to the extent that they also own or operate sources in Georgia and choose to hold Group 1 allowances in the compliance accounts for those sources). However, new § 97.526(c)(7) authorizes the use of Group 2 allowances to satisfy obligations to hold Group 1 allowances that might arise after the conversion date, such as an obligation to hold additional allowances because of excess emissions or for compliance with the assurance provisions. When held for this purpose, a single Group 2 allowance may satisfy the obligation to hold more than one Group 1 allowance, as though the conversion were reversed.

Beyond the conversion provisions, additional amendments to the Group 1 program align certain deadlines under the Group 1 program with the comparable deadlines under the new Group 2 program and the CSAPR annual programs. Although these changes were not addressed in the proposal, the EPA expects them to be noncontroversial because they impose no additional burdens and are designed to simplify program compliance and administration, thereby tending to reduce costs for both regulated parties and the EPA. Specifically, the date as of which allowances equal to emissions in the preceding control period must be held in a source's compliance account under the Group 1 program is being amended from December 1 of the year of the control period to March 1 of the following year. This change is accomplished through an amendment to the definition of ''allowance transfer deadline'' in § 97.502. In addition, the deadlines for providing notices regarding the units that are eligible for

[192] As part of several 2015 actions approving SIP revisions to modify allocations of allowances for the 2016 control period to sources in Alabama, Kansas, Missouri, and Nebraska, the EPA added language acknowledging the approved SIP revisions to the state-specific CFR sections describing the CSAPR FIPs for these states. This rule removes those previous additions to the state-specific CFR sections. *See* §§ 52.54 and 52.55 (Alabama), 52.882 (Kansas), 52.1326 (Missouri), and 52.1428 and 52.1429 (Nebraska). The removed acknowledgements are replaced by similar acknowledgements in new §§ 52.38(a)(8)(i) and (b)(12)(i) and 52.39(m)(1), and the SIP revisions remain effective notwithstanding the removal of the previous acknowledgements.

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second-round allocations of NUSA allowances and for allocating and recording those allowances are being amended from September 15 and November 15 of the year of the control period to December 15 of the year of the control period and February 15 of the following year, respectively. These changes are accomplished through amendments to §§ 97.511(b)(1)(iii) and (iv) and (2)(iii) and (iv), 97.512(a)(9)(i) and (b)(9)(i), and 97.521(i).

The final substantive revision to the Group 1 trading program in the final regulatory text is in § 97.521(c), where the deadline for the EPA to record Group 1 allowances for the control periods in 2017 and 2018 is amended to January 9, 2017, as discussed in section VII.E.7 of this preamble.

Additional proposed amendments to the Group 1 trading program regulations establishing new amounts for budgets, new unit set-asides, Indian country new unit set-asides, and variability limits and new deadlines for compliance, allowance recordation, monitor certification, and reporting are not being finalized because they concern budgets and sources under the new Group 2 trading program instead of the Group 1 trading program. The substance of the proposed amendments to deadlines is reflected in the new Group 2 trading program regulations in various subsections of new subpart EEEEE. Similarly, the amounts of the budgets, new unit set-asides, Indian country new unit set-asides, and variability limits as finalized in this rule are reflected in § 97.810 of the new Group 2 trading program regulations.

C. Group 2 Trading Program Provisions in Subpart EEEEE of Part 97

The Group 2 trading program regulations in new subpart EEEEE of part 97 generally parallel the existing Group 1 trading program regulations in subpart BBBBB of part 97 but reflect the amounts of the budgets, new unit set-asides, Indian country new unit set-asides, and variability limits established in this rule, all of which are set forth in § 97.810. That same section sets forth the amounts of a Group 2 budget, new unit set-aside, and variability limit which Georgia could adopt in a SIP revision that would be approvable under new § 52.38(b)(6).

Under § 97.806(c)(3)(i), the obligation to hold one Group 2 allowance for each ton of emissions during the control period begins with the 2017 control period, two years later than the analogous start date for the Group 1 program. The deadlines for certifying monitoring systems under § 97.830(b) and for beginning quarterly reporting under § 97.834(d)(1) are similarly two years later than the analogous Group 1 program deadlines. However, the start date for the assurance provisions for the Group 2 program under § 97.806(c)(3)(ii) is May 1, 2017. The allowance recordation deadlines under § 97.821 begin generally two years later than the comparable recordation deadlines under the Group 1 program but reach the same schedule by July 1, 2020, which is the deadline for recordation of allowances for the control period in 2024 under both programs.

Additional differences in the Group 2 program regulations relative to the Group 1 program regulations concern the use of converted Group 1 allowances. In general, the Group 2 regulations allow a Group 2 allowance that was allocated to any account as a replacement for removed Group 1 allowances to be used for all of the purposes for which any other Group 2 allowance may be used. This is accomplished by adding references to § 97.526(c)—the section under which the conversions are carried out—to the definitions of ''allocate'' and ''CSAPR NO_X Ozone Season Group 2 allowance'' in § 97.802 as well as the default order for deducting allowances for compliance purposes under § 97.824(c)(2).

Any Group 2 allowances allocated based on conversion of Group 1 allowances allocated for future years—specifically, the Group 2 allowances that could be allocated under § 97.526(c)(2) if the EPA approved a SIP revision from Georgia requiring Georgia sources to participate in the Group 2 program—would also be treated like any other Group 2 allowance for purposes of determining shares of responsibility for exceedances under the assurance provisions. New paragraph (2)(ii) of the definition of ''common designated representative's share'' in § 97.802 establishes this equivalence. However, allocations of Group 2 allowances converted from banked Group 1 allowances must be excluded for purposes of determining such shares of responsibility because such converted allowances do not represent allowances allocated from the current control period's emissions budgets. This exclusion is addressed in new paragraph (2)(i) of the definition of ''common designated representative's share'' in § 97.802.

Consistent with the proposal, the EPA has determined that, in order to facilitate NO_X SIP Call compliance, a state should be allowed to expand applicability of the Group 2 program to include any sources that previously participated in the NO_X Budget Trading Program, and that the state should be able to issue an amount of allowances beyond the CSAPR Update state budget if applicability is expanded. The EPA has further determined, again consistent with the proposal, that the assurance provisions should continue to apply only to emissions from the sources subject to the Group 2 program before any such expansion. Accordingly, the Group 2 program rules reflect certain revisions to the assurance provisions so as to exclude any additional units and allowances brought into the program through such a SIP revision.

In order to exclude the additional units, new definitions of ''base CSAPR NO_X Ozone Season Group 2 unit'' and ''base CSAPR NO_X Ozone Season Group 2 source'' are added in § 97.802 which exclude units that would not have been included in the program under § 97.804. All provisions related to the assurance provisions are amended to reference only such ''base'' units and sources. The amended provisions are §§ 97.802 (the definitions of ''assurance account'', ''common designated representative'', and ''common designated representative's share''), 97.806(c)(2) and (3)(ii), and 97.825.[193] The exclusion of the additional allowances from the determination of shares of responsibility for exceedances of the assurance provisions is accomplished through an amendment to paragraph (2) of the definition of ''common designated representative's share'' in § 97.802.

Finally, amendments to §§ 97.816, 97.818, and 97.820(c)(1) and (5) reduce the administrative compliance burden for sources in the transition from the Group 1 program to the Group 2 program by providing that certain one-time or periodic submissions made for purposes of compliance with the Group 1 program will be considered valid for purposes of the Group 2 program as well. The submissions treated in this manner are a certificate of representation or notice of delegation submitted by a designated representative and an application for a general account or notice of delegation submitted by an authorized account representative.

C. Administrative Appeal Procedures in Part 78

The final rule amends the administrative appeal provisions in part 78 in order to make the procedures of

[193] In the provisions in § 52.38(b)(9)(vii) concerning full CSAPR SIP revisions, the new definitions of ''base'' units and sources also have been included in the lists of trading program provisions that may be removed from a state's SIP revision and added to a FIP if and when a unit is located in Indian country within the state's borders.

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that part applicable to determinations of the EPA Administrator under the new Group 2 program in subpart EEEEE of part 97 in the same manner as the procedures are applicable to similar determinations under the other CSAPR trading programs and previous EPA trading programs. These amendments concern the list in § 78.1(a)(1) of CFR sections (and analogous SIP revisions) generally giving rise to determinations subject to the part 78 procedures; the list in § 78.1(b) of certain determinations that are expressly subject to those procedures; the list in § 78.3(a) of the types of persons who may seek review under the procedures; the list in § 78.3(c) of the required contents of petitions for review; the list in § 78.3(d) of matters for which a right of review is not provided; and the requirements in § 78.4(a)(1) as to who must sign a filing.

In addition, consistent with the proposal, under new § 78.1(b)(14)(viii), determinations of the EPA Administrator under § 97.526(c) regarding the removal of Group 1 allowances from accounts and the allocation in their place of Group 2 allowances are added to the list of determinations expressly subject to the part 78 procedures.

D. Nomenclature Changes

The EPA is finalizing the proposal to change the nomenclature in the CFR from ''Transport Rule'' to ''Cross-State Air Pollution Rule'' and from ''TR'' to ''CSAPR''. The change affects subparts AAAAA, BBBBB, CCCCC, and DDDDD of part 97, part 78, and all the CSAPR FIP sections in part 52 of 40 CFR.

In order to minimize administrative burden associated with the nomenclature changes, the regulations for all of the CSAPR trading programs (including the new subpart EEEEE) include provisions allowing continued use of the acronym ''TR'' instead of the acronym ''CSAPR'' in SIP revisions and in submissions by regulated parties. Language for this purpose has been included in §§ 97.502 (introductory text), 97.516, and 97.520(c)(1) and (2).[194]

[194] For brevity, in this section and the following section only the citations to subpart BBBBB are listed. Unless otherwise indicated, the citations should also be understood as representing the analogous provisions in subparts AAAAA, CCCCC, DDDDD, and potentially EEEEE which would have the same section numbers as the citations shown but with ''4'', ''6'', ''7'', or ''8'' respectively, substituted for the initial ''5'' in the section number (*e.g.,* a reference to § 97.502 is intended to also refer to §§ 97.402, 97.602, 97.702, and 97.802).

E. Technical Corrections and Clarifications

The final rule also finalizes technical corrections and clarifications throughout the sections of parts 52, 78, and 97 implementing CSAPR, including the sections implementing CSAPR's other three emissions trading programs. The EPA received no adverse comments on any of the technical corrections that were discussed in the proposal. The final rule contains some additional technical corrections that the EPA considers similarly noncontroversial.

The most common category of these minor changes consists of corrections to cross-references that as originally published indicated incorrect locations because of typographical errors or indicated correct locations but did not use the correct CFR format. In virtually all cases, the intended correct cross-reference can be determined from context, but the corrections clarify the regulations. Besides the corrections to cross-references, most of the remaining corrections address typographical errors.

A small number of the CFR changes correct errors that are not cross-references or obviously typographical errors. While the EPA views these corrections as noncontroversial, and no adverse comments were received regarding the corrections described in the proposal, they merit a short explanation.

The phrase ''with regard to the State'' or ''the State and'' has been added in a number of locations in §§ 52.38 and 52.39 where it was inadvertently omitted. The added phrase clarifies that when the EPA approves a state's SIP revision as modifying or replacing provisions in a CSAPR trading program, the modification or replacement is effective only with regard to that particular state. Correcting the omissions of these phrases makes the language concerning SIP revisions consistent for all the types of SIP revisions under all the CSAPR trading programs.

The phrase ''in part'' has been removed from the existing FIP language in various sections of part 52 for certain states with Indian country to clarify that in order to replace a CSAPR FIP affecting the sources in these states, a SIP revision must fully, not ''in part,'' correct the SIP deficiency identified by the EPA as the basis for the FIP. The intended purpose of the words ''in part''—specifically, to indicate that approval of a state's SIP revision would apply only to sources in the state and would not relieve any sources in Indian country within the borders of the state from obligations under the FIP—is already served by other language in those FIPs, and is further clarified by addition of the phrase ''for those sources and units'' (referencing the units in the state). The corrections make the language in these CSAPR FIPs consistent with the FIP language for the remaining CSAPR FIPs that address states with Indian country. Analogous changes to the general CSAPR FIP language in §§ 52.38(a)(5) and (6) and (b)(5) and (6) and 52.39(f), (i), and (j) have removed the phrase ''in whole or in part'' (referencing states without Indian country and states with Indian country, respectively) while adding language distinguishing the effect that the EPA's approval of a SIP revision has on sources in the state from the lack of effect on any sources in Indian country within the borders of the state.

Language has been added to § 78.1 clarifying that determinations by the EPA Administrator under the CSAPR trading programs that are subject to the part 78 administrative appeal procedures are subject to those procedures whether the source in question participates in a CSAPR federal trading program under a FIP or a CSAPR state trading program under an approved SIP revision. This approach is consistent with the approach taken under CAIR FIPs and SIPs and with the EPA's intent in CSAPR, as evidenced by the lack of any proposal or discussion in the CSAPR rulemaking regarding deviation from the historical approach taken under CAIR. This approach is also consistent with provisions in §§ 52.38 and 52.39 prohibiting approvable SIP revisions from altering certain provisions of the CSAPR trading programs, including the provisions specifying that administrative appeal procedures for determinations of the EPA Administrator under the trading programs are set forth in part 78.

The phrase ''steam turbine generator'' has been changed to ''generator'' in the list of required equipment in the definition of a ''cogeneration system'' in § 97.502. Absent this correction, a combustion turbine in a facility that uses the combustion turbine in combination with an electricity generator and heat recovery steam generator, but no steam turbine, to produce electricity and useful thermal energy would not meet the definition of a ''cogeneration unit.'' The correction clarifies that a combustion turbine in such a facility should be able to qualify as a ''cogeneration unit'' (assuming it meets other relevant criteria) under the CSAPR trading programs, as it could under the CAIR trading programs. The consistency of this approach with the

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EPA's intent in the CSAPR rulemaking is evidenced by the lack of any proposal or discussion in that rulemaking regarding the concept of narrowing the set of facilities qualifying for an applicability exemption as cogeneration units. To the contrary, as discussed in the preamble to the CSAPR proposal (75 FR 45307, August 2, 2010), the definition of ''cogeneration system'' was created in CSAPR to potentially broaden the set of facilities qualifying for the exemption, specifically by facilitating qualification as ''cogeneration units'' for certain units that might not meet the required levels of efficiency on an individual basis but that operate as components of multi-unit ''cogeneration systems'' that do meet the required levels of efficiency.

The deadline for recording certain allowance allocations under § 97.521(j) has been changed from ''the date on which'' the EPA receives the necessary allocation information to ''the date 15 days after the date on which'' the EPA receives the information. The EPA's lack of intention in the CSAPR rulemaking to establish the deadline as defined prior to the correction is evidenced by the impracticability of complying with such a deadline.

A change to a description of a required notice under the assurance provisions in § 97.525(b)(2)(iii)(B) has modified the phrase ''any adjustments'' to the phrase ''calculations incorporating any adjustments'' in order to clarify that the required notice will identify not only any adjustments made to previously noticed calculations, but also the complete calculations with (or without) such adjustments. The intended meaning is clear from the subsequent provisions that use this document as the point of reference for the complete calculations used in the succeeding administrative procedures.

The final rule also makes several additional technical corrections and clarifications. One set of corrections addresses the inconsistent treatment in the regulations of allowances initially distributed to sources by means of auction mechanisms instead of zero-cost allocation mechanisms. The original CSAPR regulations gave states the option to distribute allowances by auction under the provisions of an approved SIP revision, and some of the trading program provisions expressly accounted for that possibility. *See, e.g.,* §§ 52.38(b)(4) and (5); 97.502 (definitions of ''common designated representative's share'', ''CSAPR NO_X Ozone Season Group 1 allowance and ''record''), and 97.521. However, other trading program provisions, including some that define the allowances that can be used for compliance, failed to address the possible use of allowances acquired in an auction held pursuant to an approved SIP revision. The technical corrections have addressed this inadvertent omission principally by adding a definition of ''auction'' in § 97.502 and by adding references to auctioned allowances in provisions describing allowances available for use in compliance in §§ 97.506(c)(4)(i) and (ii), 97.524(a)(1) and (d), and 97.525(a). Additional changes recognizing the possible existence of auctioned allowances have been made in § 97.802 (definitions of ''Allowance Management System'' and Allowance Management System account'') and in §§ 97.523(b) and 97.524(c)(2)(i) and (ii).

Technical corrections have been made to the definitions of ''heat input'', ''heat input rate'', ''heat rate'', ''maximum heat input rate'', and ''potential electrical output capacity'' in § 97.502 in order to express the definitions in correct and clearly identified units of measurement. The corrections clarify the regulations and do not change any regulatory requirement for any unit.

In a provision in § 97.506(c)(2)(ii) stating the deadline to hold allowances for purposes of the assurance provisions, the phrase ''after such control period'' has been corrected to say ''after the year of such control period''. The change makes the deadline as described in this section consistent with the deadline as already described correctly in § 97.525(b)(4)(i).

In § 97.520(c)(5)(v), incorrect references to the ''designated representative'' have been replaced with references to the ''authorized account representative''. The EPA's intent to use the term ''authorized account representative'' is clear from the cross-references to other paragraphs of § 97.520(c)(5) where that term, rather than the term ''designated representative'', is used.

In § 97.521, a new paragraph (j) has been added to correct the inadvertent omission of any recordation deadline for second-round allocations of allowances from an Indian country NUSA. The deadlines in the new paragraph are identical to the recordation deadlines for second-round allocations of allowances from a NUSA. The EPA's intent for such deadlines to apply is evident from the provisions of §§ 97.511(b)(2) and 97.512(b) which establish schedules for the determination of allocations of allowances from Indian country NUSAs that are fully synchronized with the schedules for determination of allocations of allowances from other NUSAs.

The provisions concerning full CSAPR SIP revisions in §§ 52.38(a)(5)(iv) and (b)(5)(v) and 52.39(f)(4) and (i)(4) have been amended to include more comprehensive lists of the specific CSAPR trading program provisions that concern administration of Indian country NUSAs and that therefore should not be incorporated by a state into a full CSAPR SIP revision. The language has also been modified to clarify that mere ''references to'' units in Indian country within a state's borders are not impermissible in such SIP revisions, as long as the SIP revisions do not impose any obligations on any units in Indian country and as long as the SIP revisions remain substantively identical to the federal trading program regulations (except as otherwise expressly permitted) notwithstanding any references to units in Indian country.

In the state-specific sections of part 52, the EPA has corrected instances from the original CSAPR rulemaking where language to address sources and units in Indian country within a state's borders was inadvertently omitted from or included in the state-specific FIP language for certain states. Specifically, language addressing sources and units in Indian country has been added to the FIP language concerning annual NO_X and SO_2 emissions for Alabama in §§ 52.54(a)(1) and 52.55(a), respectively, and has been removed from the FIP language concerning annual NO_X and SO_2 emissions for Tennessee in §§ 52.2240(d)(1) and 52.2241(c)(1), respectively. These revisions make the state-specific FIP language consistent with the existing general FIP language in §§ 52.38(a)(2) and 52.39(b) and (c) making CSAPR FIP requirements applicable to any units in Indian country located within the borders of each state listed in those sections

In several provisions in part 78, cross-references that previously referred to part 97 in its entirety have been clarified to refer to only the portions of part 97 related to particular non-CSAPR trading programs, consistent with the intent of the provisions when promulgated. Specifically, general references to part 97 in §§ 78.1(a)(1) and (b)(6) and 78.3(a)(3), (c)(7), and (d) have been replaced by references to either subparts A through J (federal NO_X Budget Trading Program); subparts AA through II, AAA through III, and AAAA through IIII (CAIR); or subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE (CSAPR). In several of these sections the more precise reference lists have been further clarified through reorganization. For the same reason, former appendices A through D to part 97 have been

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redesignated as appendices A through D to subpart E of part 97, and the cross-references to those appendices in subpart E of part 97 have been updated.

In § 78.3(a)(10) and (11), the phrase ''and that is appealable under § 78.1(a)'' has been added in order to correct an inadvertent omission and clarify that, like the other paragraphs of § 78.3(a), these paragraphs are subject to the limits set in § 78.1(a). The provisions of § 78.3(a) concern the types of persons who may petition for administrative review, while the provisions of § 78.1 address the subject matter over which administrative review may be sought. The words being added to § 78.3(a)(10) and (11) are present in each of the other parallel provisions in § 78.3(a). The EPA's intent to include the words being added is evident from the fact that, without the added words, these two paragraphs concerning the persons who may petition for administrative review could be misread as expanding the matters for which administrative review may be sought, in conflict with the provisions of § 78.1(a).

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Final Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS'', is available in the docket and is briefly summarized in section VIII of this preamble.

Consistent with Executive Orders 12866 and 13563, the EPA estimated the costs and benefits for three regulatory control alternatives: The final rule EGU NO_X ozone season emission budgets and more and less stringent alternatives. This final action reduces ozone season NO_X emissions from EGUs in 22 eastern states. Actions taken to comply with the EGU NO_X ozone season emission budgets also reduce emissions of other criteria air pollutants, including annual NO_X and associated $PM_{2.5}$ concentrations, and CO_2. The benefits associated with these co-pollutant reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The RIA for this rule analyzed illustrative compliance approaches for implementing the FIPs. This action establishes EGU NO_X ozone season emission budgets for 22 states and implements these budgets via the existing CSAPR NO_X ozone season allowance trading program.

The EPA evaluated the costs, benefits, and impacts of implementing the EGU NO_X ozone season emission budgets developed using uniform control stringency represented by $1,400 per ton. In addition, the EPA also assessed implementation of one more and one less stringent alternative EGU NO_X ozone season emission budgets, developed using uniform control stringency represented by $3,400 per ton and $800 per ton, respectively. The EPA evaluated the impact of implementing these emission budgets to reduce interstate transport for the 2008 ozone NAAQS in 2017. More details for this assessment can be found in the Regulatory Impact Analysis in the docket for this rule.

The EPA notes that its analysis of the regulatory control alternatives (*i.e.,* the final rule and more and less stringent alternatives) is illustrative in nature, in part because the EPA implements the EGU NO_X emission budgets via a regional NO_X ozone season allowance trading program. This implementation approach provides utilities with the flexibility to determine their own compliance path. The EPA's assessment develops and analyzes one possible scenario for implementing the NO_X budgets in this action and one possible scenario for implementing the more and less stringent alternatives. Furthermore, the emission budgets evaluated for the CSAPR Update regulatory control alternative in this benefit and cost analysis are illustrative because they differ somewhat from the budgets finalized in this rule. (The budgets for the more and less stringent alternative also differ somewhat from the budgets represented by $3,400 per ton and $800 per ton reported in Table VI.C–1). However, the RIA also reports the costs and emissions changes associated with the finalized budgets. Further details on the illustrative nature of this analysis can be found in the RIA in the docket for this rule.

The EPA estimates the costs associated with compliance with the illustrative regulatory control alternative to be approximately $68 million (2011$) annually. These costs represent the private compliance cost of reducing NO_X emissions to comply with the final rule.

In this analysis, the EPA monetized the estimated benefits associated with the reduced exposure to ozone and $PM_{2.5}$ and co-benefits of decreased emissions of CO_2, but was unable to quantify or monetize the potential co-benefits associated with reducing exposure to NO_2 as well as ecosystem effects and reduced visibility impairment from reducing NO_X emissions. Specifically, the EPA estimated combinations of health benefits at discount rates of 3 percent and 7 percent (as recommended by the EPA's *Guidelines for Preparing Economic Analyses* [U.S. EPA, 2014] and OMB's *Circular A–4* [OMB, 2003]) and climate co-benefits of CO_2 reductions at discount rates of 5 percent, 3 percent, 2.5 percent, and 3 percent (95th percentile) (as recommended by the interagency working group). The EPA estimates the monetized ozone-related benefits[195] of the final rule to be $370 million to $610 million (2011$) in 2017 and the $PM_{2.5}$-related co-benefits[196] of the rule to be $93 million to $210 million (2011$) using a 3 percent discount rate and $83 million to $190 million (2011$) using a 7 percent discount rate. Further, the EPA estimates CO_2-related co-benefits of $54 to $87 million (2011$). Additional details on this analysis are provided in the RIA for this final rule. Tables X.A–1, X.A–2, and X.A–3 summarize the quantified human health and climate benefits and the costs of the rule and the more and less stringent control alternatives.

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195 The ozone-related health benefits range is based on applying different adult mortality functions (*i.e.,* Smith *et al.* (2009) and Zanobetti and Schwartz (2008)).

196 The $PM_{2.5}$-related health co-benefits range is based on applying different adult mortality functions (*i.e.,* Krewski *et al.* (2009) and Lepeule *et al.* (2012)).

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TABLE X.A–1—ESTIMATED HEALTH BENEFITS OF PROJECTED 2017 EMISSIONS REDUCTIONS FOR THE FINAL RULE AND MORE OR LESS STRINGENT ALTERNATIVES

[Millions of 2011$] [1 2]

	Final rule	More stringent	Less stringent
NO_X (as ozone)	$370 to $610	$400 to $650	$160 to $270
NO_X (as $PM_{2.5}$):			
3% Discount Rate	$93 to $210	$98 to $220	$34 to $75
7% Discount Rate	$83 to $190	$88 to $200	$30 to $67
Total:			
3% Discount Rate	$460 to $810	$500 to $870	$200 to $340
7% Discount Rate	$450 to $790	$490 to $850	$190 to $330

[1] The health benefits range is based on adult mortality functions (*e.g.*, from Krewski et al. (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Zanobetti and Schwartz (2008)).

[2] All estimates are rounded to two significant figures.

TABLE X.A–2—ESTIMATED GLOBAL CLIMATE CO-BENEFITS OF CO_2 REDUCTIONS FOR THE FINAL RULE AND MORE OR LESS STRINGENT ALTERNATIVES

[Millions of 2011$] [1]

Discount rate and statistic	Final rule	More stringent	Less stringent
5% (average)	$19	$25	$15
3% (average)	66	87	54
2.5% (average)	100	130	81
3% (95th percentile)	190	250	150

[1] The social cost of carbon (SC–CO_2) values are dollar-year and emissions-year specific. SC–CO_2 values represent only a partial accounting of climate impacts.

The EPA combined this information to perform a benefit-cost analysis for this action (shown in table VIII.6 and for the more and less stringent alternatives—shown in the RIA in the docket for this rule).

TABLE X.A–3—TOTAL COSTS, TOTAL MONETIZED BENEFITS, AND NET BENEFITS OF THE FINAL RULE IN 2017 FOR U.S.

[Millions of 2011$] [1]

Air Quality Health Benefits	$460 to $810 [2] and $450 to $790. [3]
Total Benefits	$530 to $880 [2] and $520 to $860. [3]
Annualized Costs Compliance Costs	$68 [4]
Net Benefits	$460 to $810 [2] and $450 to $790. [3]
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2. Ecosystem benefits and visibility improvement assoc. with reductions in emissions of NO_X.

[1] All estimates are rounded to two significant figures.

[2] 3% discount rate.

[3] 7% discount rate.

[4] These costs do not include monitoring, recordkeeping, and reporting costs, which are reported separately. See Chapter 4 of the RIA for this final rule for details and explanation.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, the EPA's estimates of the co-benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include co-benefits from reducing direct exposure to NO_2 as well as from reducing ecosystem effects and visibility impairment from reducing NO_X emissions. Based upon the foregoing discussion, it remains clear that the benefits of this action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in the RIA for this final rule.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2391.05. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The information generated by information collection activities under CSAPR is used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable the EPA or states to identify affected facilities that may not be in compliance with the requirements. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are established pursuant to CAA sections 110(a)(2)(D) and (c) and 301(a) (42 U.S.C. 7410(a)(2)(D) and (c) and 7601(a)) and are specifically authorized by CAA section 114 (42

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U.S.C. 7414). Reported data may also be used for other regulatory and programmatic purposes. All information submitted to the EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

All of the EGUs that are subject to changed information collection requirements under this rule are already subject to information collection requirements under CSAPR. Most of these EGUs also are already subject to information collection requirements under the Acid Rain Program (ARP) established under Title IV of the 1990 Clean Air Act Amendments. Both CSAPR and the ARP have existing approved ICRs: EPA ICR Number 2391.03/OMB Control Number 2060–0667 (CSAPR) and EPA ICR Number 1633.16/OMB Control Number 2060–0258 (ARP). The burden and costs of the information collection requirements covered under the CSAPR ICR are estimated as incremental to the information collection requirements covered under the ARP ICR. Most of the information used to estimate burden and costs in this ICR was developed for the existing CSAPR and ARP ICRs.

This rule changes the universe of sources subject to certain information collection requirements under CSAPR but does not change the substance of any CSAPR information collection requirements. The burden and costs associated with the changes in the reporting universe are estimated as reductions from the burden and costs under the existing CSAPR ICR. (This rule does not change any source's information collection requirements with respect to the ARP.) The EPA intends to incorporate the burden and costs associated with the changes in the reporting universe under this rulemaking into the next renewal of the CSAPR ICR.

Respondents/affected entities: Entities potentially affected by this action are EGUs in the states of Florida, Kansas, North Carolina, and South Carolina that meet the applicability criteria for the CSAPR NO_X ozone season Group 1 and Group 2 trading programs in 40 CFR 97.504 and 97.804.

Respondent's obligation to respond: Mandatory (sections 110(a), 110(c), and 301(a) of the Clean Air Act).

Estimated number of respondents: 138 sources in Florida, Kansas, North Carolina, and South Carolina with one or more EGUs.

Frequency of response: Quarterly, occasionally.

Total estimated burden: Reduction of 12,879 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: Reduction of $1,347,291 (per year), includes reduction of $409,786 operation and maintenance costs.

The burden and cost estimates above reflect the reduction in burden and cost for Florida sources with EGUs that would no longer be required to report NO_X mass emissions and heat input data for the ozone season to the EPA under the rule and that are not subject to similar information collection requirements under the Acid Rain Program. Because these EGUs would no longer need to collect NO_X emissions or heat input data under 40 CFR part 75, the estimates above also reflect the reduction in burden and cost to collect and quality assure these data and to maintain the associated monitoring equipment.

The EPA estimates that the rule causes no change in information collection burden or cost for EGUs in Kansas that would be required to report NO_X mass emissions and heat input data for the ozone season to the EPA or for EGUs in North Carolina or South Carolina that would no longer be required to report NO_X emissions and heat input data for the ozone season to the EPA. The EGUs in Kansas, North Carolina, and South Carolina already are and would remain subject to requirements to report NO_X mass emissions and heat input data for the entire year to the EPA under the CSAPR NO_X Annual Trading Program, and the requirements related to ozone season reporting are a subset of the requirements related to annual reporting. Similarly, the EPA estimates that the rule causes no change in information collection burden or cost for EGUs in Florida that are subject to the Acid Rain Program because of the close similarity between the information collection requirements under CSAPR and under the Acid Rain Program. The EPA also estimates that the rule causes no change in information collection burden or cost for EGUs in the states have been covered by the current CSAPR NO_X Ozone Season Group 1 Trading Program and starting in 2017 will be covered by the new CSAPR NO_X Ozone Season Group 2 Trading Program because the information collection requirements applicable to an individual source under the two programs are identical.

The comments received in response to the proposal included no comments regarding the ICR for this final rule, but did include one comment regarding the existing CSAPR ICR. The comment noted that the existing CSAPR ICR should have been renewed in order to remain valid past July 31, 2014, but that OMB had not acted on the EPA's renewal submission as of that date. The commenter is correct as to those facts, but the commenter's apparent suggestion that the existing CSAPR ICR may have lapsed as of that date is incorrect. The EPA made a timely renewal submission for that ICR, and an agency may continue to collect information pursuant to a previously approved ICR if a timely renewal submission for the ICR has been made, pending OMB action on the submission. 5 CFR 1320.10(e)(2). Further, prior to the date when the comment was submitted, OMB did in fact approve the EPA's renewal submission for the CSAPR ICR.

More information on the ICR analysis is included in the docket for this rule.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses, small organizations, and small governmental jurisdictions.

The EPA has lessened the impacts for small entities by excluding all units 25 MWe or less. This exclusion, in addition to the exemptions for cogeneration units and solid waste incineration units, eliminates the burden of higher costs for a substantial number of small entities located in the 22 states for which the EPA is finalizing FIPs.

Within these states, the EPA identified a total of 365 potentially affected EGUs (*i.e.,* greater than 25 MWe) warranting examination in its RFA analysis. Of these, the EPA identified 30 potentially affected EGUs that are owned by 11 entities that met the Small Business Administration's criteria for identifying small entities. The EPA estimated the annualized net compliance cost to these 11 small entities to be approximately $23.9 million in 2017. Of the 11 small entities

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considered in this analysis, 1 entity may experience compliance costs greater than 1 or 3 percent of generation revenues in 2017. The EPA notes that this entity is located in a cost of service market, where the agency typically expects that entities should be able to recover all of their costs of complying with the final rule.

The EPA has concluded that there is no significant economic impact on a substantial number of small entities (no SISNOSE) for this rule. Details of this analysis are presented in the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. According to the EPA's analysis, the total net economic impact on government owned entities (state- and municipality-owned utilities and subdivisions) is expected to be $20.5 million in 2017. Note that the EPA expects the rule to potentially have an impact on 11 municipality-owned entities and 1 state-owned entity. This analysis does not examine potential indirect economic impacts associated with the rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on government entities. For more information on the estimated impact on government entities, refer to the RIA, which is in the public docket.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

This final action implements EGU NO_X ozone season emissions reductions in 22 eastern states. However, at this time, none of the existing or planned EGUs affected by this rule are owned by tribes or located in Indian country. This action may have tribal implications if a new affected EGU is built in Indian country. Additionally, tribes have a vested interest in how this rule affects air quality.

In developing the original CSAPR, which was published on August 8, 2011 to address interstate transport of ozone pollution under the 1997 ozone NAAQS,[197] the EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing that regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in 76 FR 48346 (August 8, 2011).

The EPA received comments from several tribal commenters regarding the availability of CSAPR allowance allocations to new units in Indian country. The EPA responded to these comments by instituting Indian country new unit set-asides in the final CSAPR. In order to protect tribal sovereignty, these set-asides are managed and distributed by the federal government regardless of whether CSAPR in the adjoining or surrounding state is implemented through a FIP or SIP. While there are no existing affected EGUs in Indian country covered by the CSAPR Update, the Indian country set-asides will ensure that any future new units built in Indian country will be able to obtain the necessary allowances. The CSAPR Update maintains the Indian country new unit set-aside and adjusts the amounts of allowances in each set-aside according to the same methodology of the original CSAPR rule, with one small correction.

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. The EPA informed tribes of its development of this rule on a regularly scheduled National Tribal Air Association—EPA air policy monthly conference call (January 29, 2015) and gave an overview of the proposed rule on a separate call (November 17, 2015). In December 2015, the EPA offered consultation to tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes to permit them to have meaningful and timely input into the development of the final rule. The EPA sent letters to all 566 federally-recognized tribes informing them of this action, offering consultation and requesting comment on this rulemaking. Letters were also sent via email to tribal air staff. The EPA received no requests for consultation on this rule.

As part of the public comment process, we received one letter from the National Tribal Air Association (NTAA) that highlighted the need for an Indian country new unit set aside for the Poarch Band of Creek Indians in Alabama. EPA made this adjustment in the final rule and addressed the NTAA's other comments in the Response to Comments document, available in the docket, for this final action.

In order to help tribes to better understand this final action and how it could affect their communities, the EPA is providing an interactive map of affected sources and Indian country. This map will be available online. The EPA will continue to engage with tribes as part of the outreach strategy for this final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. However, the EPA believes that the ozone-related benefits, $PM_{2.5}$-related co-benefits, and CO_2-related co-benefits would further improve children's health.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action, which is a significant regulatory action under Executive Order 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA noted in the proposal that one aspect of this rule that could affect energy supply, disposition, or use was the EPA's proposing and taking comment on a range of options with respect to use of 2015 vintage and 2016 vintage CSAPR NO_X ozone season allowances for compliance with 2017 and later ozone season requirements. The EPA did not finalize actions that could have eliminated the allowance

[197] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.

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bank but is converting the 2015 and 2016 vintage CSAPR allowances to a currency that can be used for compliance in 2017 and beyond. The EPA prepared a Statement of Energy Effects for the regulatory control alternative as follows: The agency estimates no change in retail electricity prices on average across the contiguous U.S. in 2017 as a result of this rule, and a much less than 1 percent reduction in coal-fired electricity generation in 2017 as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2017. For more information on the estimated energy effects, refer to the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994).

The EPA notes that this action updates CSAPR to reduce interstate ozone transport with respect to the 2008 ozone NAAQS. This rule uses the EPA's authority in CAA section 110(a)(2)(d) to reduce NO_X pollution that significantly contributes to downwind ozone nonattainment or maintenance areas. As a result, the rule will reduce exposures to ozone in the most-contaminated areas (*i.e.,* areas that are not meeting the 2008 ozone NAAQS). In addition, the rule separately identifies both nonattainment areas and maintenance areas. This requirement reduces the likelihood that areas close to the level of the standard will exceed the current health-based standards in the future. The EPA implements these emission reductions using the CSAPR EGU NO_X ozone season emissions trading program with assurance provisions.

The EPA recognizes that some communities have voiced concerns in the past about emission trading and the potential for emission increases in any location from an environmental justice perspective. The EPA believes that CSAPR mitigated these concerns and that this final rule, which applies the CSAPR framework to reduce interstate ozone pollution and implement these reductions, will also alleviate community concerns.

Ozone pollution from power plants has both local and regional components: part of the pollution in a given location—even in locations near emission sources—is due to emissions from nearby sources, and part is due to emissions that travel hundreds of miles and mix with emissions from other sources.

It is important to note that the section of the Clean Air Act providing authority for this rule, section 110(a)(2)(D), unlike some other provisions, does not dictate levels of control for particular facilities. In developing the original CSAPR, the EPA considered several alternative implementation approaches, and found that none of the approaches could ensure that all affected power plants would decrease their emissions. For example, under an alternative approach that required direct emission controls on individual facilities, the emission rate for each facility would have been limited but individual facilities could emit more pollution overall by increasing their power output.[198]

CSAPR allows sources to trade allowances with other sources in the same or different states while firmly limiting any emissions shifting that may occur by requiring a strict emission ceiling in each state (the assurance level). In addition, assurance provisions in the existing CSAPR regulations that will remain in place under this rule outline the allowance surrender penalties for failing to meet the assurance level; there are additional allowance penalties as well as financial penalties for failing to hold an adequate number of allowances to cover emissions.

This approach reduces EGU emissions in each state that significantly contribute to downwind nonattainment or maintenance areas, while allowing power companies to adjust generation as needed and ensure that the country's electricity needs will continue to be met. The EPA maintains that the existence of these assurance provisions, including the penalties imposed when triggered, will ensure that state emissions will stay below the level of the budget plus variability limit.

In addition, all sources must hold enough allowances to cover their emissions. Therefore, if a source emits more than its allocation in a given year, either another source must have used less than its allocation and be willing to sell some of its excess allowances, or the source itself had emitted less than its allocation in one or more previous years (*i.e.,* banked, or saved, allowances for future use).

In summary, the CSAPR addresses community concerns about localized hot spots and reduces ambient concentrations of pollution where they are most needed by sensitive and vulnerable populations by: Considering the science of ozone transport to set strict state emission budgets to reduce significant contributions to ozone nonattainment and maintenance (*i.e.,* the most polluted) areas; implementing air quality-assured trading; requiring any emissions above the level of the allocations to be offset by emission decreases; and imposing strict penalties for sources that contribute to a state's exceedance of its budget plus variability limit. In addition, it is important to note that nothing in this final rule allows sources to violate their title V permit or any other federal, state, or local emissions or air quality requirements.

It is also important to note that CAA section 110(a)(2)(D), which addresses transport of criteria pollutants between states, is only one of many provisions of the CAA that provide the EPA, states, and local governments with authorities to reduce exposure to ozone in communities. These legal authorities work together to reduce exposure to these pollutants in communities, including for minority, low-income, and tribal populations, and provide substantial health benefits to both the general public and sensitive sub-populations.

The EPA informed communities of its development of this rule on an Environmental Justice community call (January 28, 2015) and two National Tribal Air Association—EPA air policy conference calls (January 29, 2015 and November 17, 2015). The EPA will continue to engage with communities and tribes as part of the outreach strategy for this final rule.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Judicial Review and Determinations Under Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations

[198] 76 FR 48348 (August 8, 2011).

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promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

The EPA finds that any final action related to this rulemaking is ''nationally applicable'' and of ''nationwide scope and effect'' within the meaning of section 307(b)(1). Through this rulemaking action, the EPA interprets section 110 of the CAA, a provision which has nationwide applicability. In addition, the rule applies to 22 States. The rule is also based on a common core of factual findings and analyses concerning the transport of pollutants between the different states subject to it. For these reasons, the Administrator determines that this final action is of nationwide scope and effect for purposes of section 307(b)(1). Thus, pursuant to section 307(b) any petitions for review of any final actions regarding the rulemaking would be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date any final action is published in the **Federal Register**.

In addition, pursuant to sections 307(d)(1)(C) and 307(d)(1)(V) of the CAA, the Administrator determines that this action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, to ''the promulgation or revision of an implementation plan by the Administrator under CAA section 110(c).'' 42 U.S.C. 7407(d)(1)(B). Under section 307(d)(1)(V), the provisions of section 307(d) also apply to ''such other actions as the Administrator may determine.'' 42 U.S.C. 7407(d)(1)(V). The agency has complied with procedural requirements of CAA section 307(d) during the course of this rulemaking.

List of Subjects

40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

40 CFR Part 78

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Reporting and recordkeeping requirements.

Dated: September 7, 2016.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, parts 52, 78, and 97 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

§§ 52.38, 52.39, 52.54, 52.55, 52.584, 52.585, 52.731, 52.732, 52.789, 52.790, 52.840, 52.841, 52.882, 52.883, 52.940, 52.941, 52.1084, 52.1085, 52.1186, 52.1187, 52.1240, 52.1241, 52.1326, 52.1327, 52.1428, 52.1429, 52.1584, 52.1585, 52.1684, 52.1685, 52.1784, 52.1785, 52.1882, 52.1883, 52.2040, 52.2041, 52.2140, 52.2141, 52.2240, 52.2241, 52.2283, 52.2284, 52.2440, 52.2441, 52.2540, 52.2541, 52.2587, and 52.2588 [Amended]

■ 2. Sections 52.38, 52.39, 52.54, 52.55, 52.584, 52.585, 52.731, 52.732, 52.789, 52.790, 52.840, 52.841, 52.882, 52.883, 52.940, 52.941, 52.1084, 52.1085, 52.1186, 52.1187, 52.1240, 52.1241, 52.1326, 52.1327, 52.1428, 52.1429, 52.1584, 52.1585, 52.1684, 52.1685, 52.1784, 52.1785, 52.1882, 52.1883, 52.2040, 52.2041, 52.2140, 52.2141, 52.2240, 52.2241, 52.2283, 52.2284, 52.2440, 52.2441, 52.2540, 52.2541, 52.2587, and 52.2588 are amended by removing the text ''TR'' wherever it appears and adding in its place the text ''CSAPR''.

Subpart A—General Provisions

§ 52.36 [Amended]

■ 3. Section 52.36, paragraph (e)(1)(i) is amended by removing the text ''paragraphs (a) through (e)'' and adding in its place the text ''paragraphs (a) through (c)''.

■ 4. Section 52.38 is amended by:

■ a. Revising the section heading;

■ b. After the text ''NO_X Ozone Season'' wherever it appears adding the text ''Group 1'';

■ c. In paragraph (a)(2), removing the words ''the sources in'' and adding in their place the words ''sources in each of'';

■ d. In paragraph (a)(3)(ii), after the text ''2016, of'' adding the word ''the'';

■ e. In paragraph (a)(3)(v)(A), removing the word ''paragraph'' and adding in its place the word ''paragraphs'';

■ f. In paragraph (a)(4)(i)(B), table heading, removing the word ''annual'' and adding in its place the word ''Annual'', and removing the word ''administrator'' and adding in its place the words ''the Administrator'';

■ g. In paragraph (a)(4)(ii), removing the words ''section for'' and adding in their place the words ''section applicable to'';

■ h. Revising paragraph (a)(5) introductory text;

■ i. In paragraph (a)(5)(i)(B), table heading, removing the word ''annual'' and adding in its place the word ''Annual'', and removing the word ''administrator'' and adding in its place the words ''the Administrator'';

■ j. Revising paragraphs (a)(5)(iv) and (v);

■ k. In paragraph (a)(5)(vi), removing the text ''paragraphs (a)(5)(i) and (ii)'' and adding in its place the text ''paragraph (a)(5)(i)'';

■ l. Revising paragraph (a)(6);

■ m. In paragraph (a)(7), removing the words ''a State'' and adding in their place the words ''the State'';

■ n. Adding paragraph (a)(8);

■ o. Revising paragraphs (b)(1) and (2);

■ p. In paragraph (b)(3) introductory text, removing the text ''paragraph (b)(2)'' and adding in its place the text ''paragraph (b)(2)(i) or (ii)'';

■ q. In paragraph (b)(3)(ii), after the text ''2016, of'' adding the word ''the'';

■ r. In paragraph (b)(3)(v)(A), removing the word ''paragraph'' and adding in its place the word ''paragraphs'';

■ s. In paragraph (b)(4) introductory text, removing the text ''paragraph (b)(2)'' and adding in its place the text ''paragraph (b)(2)(i)'';

■ t. Revising paragraph (b)(4)(i);

■ u. In paragraph (b)(4)(ii) introductory text, after the words ''with regard to'' adding the words ''the State and'';

■ v. In paragraph (b)(4)(ii)(B), table heading, removing the word ''administrator'' and adding in its place the words ''the Administrator'';

■ w. Revising paragraph (b)(5) introductory text, paragraph (b)(5)(i), and paragraph (b)(5)(ii) introductory text;

■ x. In paragraph (b)(5)(ii)(B), removing the words ''auction of'' and adding in their place the words ''auctions of'', and removing from the table heading the word ''administrator'' and adding in its place the words ''the Administrator'';

■ y. In paragraph (b)(5)(ii)(C), removing the words ''any control'' and adding in

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their place the words ''any such control'';

■ z. In paragraph (b)(5)(iii), after the words ''May adopt'' adding a comma;

■ aa. Revising paragraphs (b)(5)(v) through (vii), and (b)(6) and (7); and

■ bb. Adding paragraphs (b)(8) through (13).

The revisions and additions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

(a) * * *

(5) Notwithstanding the provisions of paragraph (a)(1) of this section, a State listed in paragraph (a)(2) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1) through (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR NO_X Annual Trading Program set forth in §§ 97.402 through 97.435 of this chapter, except that the SIP revision:

* * * * *

(iv) Must not include any of the requirements imposed on any unit in Indian country within the borders of the State in the provisions in §§ 97.402 through 97.435 of this chapter and must not include the provisions in §§ 97.411(b)(2) and (c)(5)(iii), 97.412(b), and 97.421(h) and (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(v) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.402 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.406(c)(2), and 97.425 of this chapter and the portions of other provisions of subpart AAAAA of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

* * * * *

(6) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1) through (4) of this section for sources in the State, the provisions of paragraph (a)(2) of this section will no longer apply to sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

* * * * *

(8) The following States have SIP revisions approved by the Administrator under paragraph (a)(3), (4), or (5) of this section:

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (a)(3) of this section as replacing the CSAPR NO_X Annual allowance allocation provisions in § 97.411(a) of this chapter with regard to the State and the control period in 2016: Alabama, Kansas, Missouri, and Nebraska.

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (a)(4) of this section as replacing the CSAPR NO_X Annual allowance allocation provisions in §§ 97.411(a) and (b)(1) and 97.412(a) of this chapter with regard to the State and the control period in 2017 or any subsequent year: Kansas and Missouri.

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (a)(5) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1) through (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): Alabama.

(b)(1) The CSAPR NO_X Ozone Season Group 1 Trading Program provisions and the CSAPR NO_X Ozone Season Group 2 Trading Program provisions set forth respectively in subparts BBBBB and EEEEE of part 97 of this chapter constitute the CSAPR Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season, defined as May 1 through September 30 of a calendar year.

(2)(i) The provisions of subpart BBBBB of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions in 2015 and each subsequent year: Georgia.

(ii) The provisions of subpart BBBBB of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2015 and 2016 only: Alabama, Arkansas, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

(iii) The provisions of subpart EEEEE of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2017 and each subsequent year: Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

* * * * *

(4) * * *

(i) The State may adopt, as applicability provisions replacing the provisions in § 97.504(a)(1) and (2) of this chapter with regard to the State, provisions substantively identical to those provisions, except that the words ''more than 25 MWe'' are replaced, wherever such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more''; and

* * * * *

(5) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2)(i) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 1 Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

(i) May adopt, as applicability provisions replacing the provisions in § 97.504(a)(1) and (2) of this chapter

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with regard to the State, provisions substantively identical to those provisions, except that the words ''more than 25 MWe'' are replaced, wherever such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more''; and

(ii) May adopt, as CSAPR NO_X Ozone Season Group 1 allowance allocation provisions replacing the provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to the State and the control period in 2017 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 1 allowances and that—

* * * * *

(v) Must not include any of the requirements imposed on any unit in Indian country within the borders of the State in the provisions in §§ 97.502 through 97.535 of this chapter and must not include the provisions in §§ 97.511(b)(2) and (c)(5)(iii), 97.512(b), and 97.521(h) and (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vi) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.502 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.506(c)(2), and 97.525 of this chapter and the portions of other provisions of subpart BBBBB of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(vii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(5)(i) through (v) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (b)(5)(ii)(B) and (C) of this section applicable to the first control period for which the State wants to replace the applicability provisions, make allocations, or hold an auction under paragraph (b)(5)(i) or (ii) of this section.

(6) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2)(i) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, subject to the following requirements and exceptions:

(i) The provisions of paragraphs (b)(9)(i) through (viii) of this section apply to any such SIP revision.

(ii) Following promulgation of an approval by the Administrator of such a SIP revision:

(A) The provisions of the SIP revision will apply to sources in the State with regard to emissions occurring in the control period that begins May 1 immediately after promulgation of such approval, or such later control period as may be adopted by the State in its regulations and approved by the Administrator in the SIP revision, and in each subsequent control period.

(B) Notwithstanding the provisions of paragraph (b)(6)(ii)(A) of this section, if, at the time of the approval of the SIP revision, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances to units in the State for a control period in any year, the Administrator will not record allocations of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for any such control period under the provisions of the SIP revision but instead will allocate and record CSAPR NO_X Ozone Season Group 2 allowances in place of CSAPR NO_X Ozone Season Group 1 allowances under § 97.526(c)(2) of this chapter, unless provided otherwise by such approval of the SIP revision.

(7) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 2 allowance allocation provisions replacing the provisions in § 97.811(a) of this chapter with regard to the State and the control period in 2018, a list of CSAPR NO_X Ozone Season Group 2 units and the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and commenced commercial operation before January 1, 2015;

(ii) The total amount of CSAPR NO_X Ozone Season Group 2 allowance allocations on the list must not exceed the amount, under § 97.810(a) of this chapter for the State and the control period in 2018, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the new unit set-aside and Indian country new unit set-aside;

(iii) The list must be submitted electronically in a format specified by the Administrator; and

(iv) The SIP revision must not provide for any change in the units and allocations on the list after approval of the SIP revision by the Administrator and must not provide for any change in any allocation determined and recorded by the Administrator under subpart EEEEE of part 97 of this chapter;

(v) Provided that:

(A) By December 27, 2016, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraphs (b)(7)(i) through (iv) of this section by April 1, 2017; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(7)(v)(A) of this section by April 1, 2017.

(8) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations revising subpart EEEEE of part 97 of this chapter as follows and not making any other substantive revisions of that subpart:

(i) The State may adopt, as applicability provisions replacing the provisions in § 97.804(a)(1) and (2) of this chapter with regard to the State, provisions substantively identical to those provisions, except that the words ''more than 25 MWe'' are replaced, wherever such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more'';

(ii) Such a State listed in § 51.121(c) of this chapter may adopt, as applicability provisions replacing the provisions in § 97.804(a) and (b) of this chapter with regard to the State, provisions substantively identical to those provisions, except that

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applicability is expanded to include, in addition to all units in the State that would be CSAPR NO_X Ozone Season Group 2 units under § 97.804(a) and (b) of this chapter and any units to which the State elects to expand applicability pursuant to paragraph (b)(8)(i) of this section, all other units that would have been subject to the State's emissions trading program regulations approved as a SIP revision under § 51.121(p) of this chapter except units to which the State is authorized to expand applicability under paragraph (b)(8)(i) of this section; and

(iii) The State may adopt, as CSAPR NO_X Ozone Season Group 2 allowance allocation or auction provisions replacing the provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter with regard to the State and the control period in 2019 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 2 allowances and may adopt, in addition to the definitions in § 97.802 of this chapter, one or more definitions that shall apply only to terms as used in the adopted CSAPR NO_X Ozone Season Group 2 allowance allocation or auction provisions, if such methodology—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(8)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 2 allowances not exceeding the lesser of:

(1) The highest of the sum, for all additional units in the State to which applicability is expanded pursuant to paragraph (b)(8)(ii) of this section, of the NO_X emissions reported in accordance with part 75 of this chapter for the ozone season in the year before the year of the submission deadline for the SIP revision under paragraph (b)(8)(iv) of this section and the corresponding sums of the NO_X emissions reported in accordance with part 75 of this chapter for each of the two immediately preceding ozone seasons, provided that each such seasonal sum shall exclude the amount of any NO_X emissions reported by any unit for all hours in any calendar day during which the unit did not have at least one quality-assured monitor operating hour, as defined in § 72.2 of this chapter; or

(2) The portion of the emissions budget under the State's emissions trading program regulations approved as a SIP revision under § 51.121(p) of this chapter that is attributable to the units to which applicability is expanded pursuant to paragraph (b)(8)(ii) of this section.

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 2 allowances for any such control period to any CSAPR NO_X Ozone Season Group 2 units covered by § 97.811(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which CSAPR NO_X Ozone season group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
2019	June 1, 2018.
2020	June 1, 2018.
2021	June 1, 2019.
2022	June 1, 2019.
2023	June 1, 2020.
2024	June 1, 2020.
2025 and any year thereafter	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 2 allowances for any such control period to any CSAPR NO_X Ozone Season Group 2 units covered by §§ 97.811(b)(1) and 97.812(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (b)(8)(iii)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart EEEEE of part 97 of this chapter or § 97.526(c) of this chapter;

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(8)(i), (ii), or (iii) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (b)(8)(iii)(B) and (C) of this section applicable to the first control period for which the State wants to replace the applicability provisions, make allocations, or hold an auction under paragraph (b)(8)(i), (ii), or (iii) of this section.

(9) Notwithstanding the provisions of paragraph (b)(1) of this section, a State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(7) and (8) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, except that the SIP revision:

(i) May adopt, as applicability provisions replacing the provisions in § 97.804(a)(1) and (2) of this chapter with regard to the State, provisions substantively identical to those provisions, except that the words "more than 25 MWe" are replaced, wherever

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such words appear, by words specifying a uniform lower limit on the amount of megawatts that is not greater than the amount specified by the words ''more than 25 MWe'' and is not less than the amount specified by the words ''15 MWe or more'';

(ii) In the case of such a State listed in § 51.121(c) of this chapter, may adopt, as applicability provisions replacing the provisions in § 97.804(a) and (b) of this chapter with regard to the State, provisions substantively identical to those provisions, except that applicability is expanded to include, in addition to all units in the State that would be CSAPR NO_X Ozone Season Group 2 units under § 97.804(a) and (b) of this chapter and any units to which the State elects to expand applicability pursuant to paragraph (b)(9)(i) of this section, all other units that would have been subject to the State's emissions trading program regulations approved as a SIP revision under § 51.121(p) of this chapter except units to which the State is authorized to expand applicability under paragraph (b)(9)(i) of this section; and

(iii) May adopt, as CSAPR NO_X Ozone Season Group 2 allowance allocation provisions replacing the provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter with regard to the State and the control period in 2019 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 2 allowances and that—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(9)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 2 allowances not exceeding the lesser of:

(*1*) The highest of the sum, for all additional units in the State to which applicability is expanded pursuant to paragraph (b)(9)(ii) of this section, of the NO_X emissions reported in accordance with part 75 of this chapter for the ozone season in the year before the year of the submission deadline for the SIP revision under paragraph (b)(9)(viii) of this section and the corresponding sums of the NO_X emissions reported in accordance with part 75 of this chapter for each of the two immediately preceding ozone seasons, provided that each such seasonal sum shall exclude the amount of any NO_X emissions reported by any unit for all hours in any calendar day during which the unit did not have at least one quality-assured monitor operating hour, as defined in § 72.2 of this chapter; or

(*2*) The portion of the emissions budget under the State's emissions trading program regulations approved as a SIP revision under § 51.121(p) of this chapter that is attributable to the units to which applicability is expanded pursuant to paragraph (b)(9)(ii) of this section.

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 2 allowances for any such control period to any CSAPR NO_X Ozone Season Group 2 units covered by § 97.811(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator no later than the following dates:

Year of the control period for which CSAPR NO_X Ozone season group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
2019	June 1, 2018.
2020	June 1, 2018.
2021	June 1, 2019.
2022	June 1, 2019.
2023	June 1, 2020.
2024	June 1, 2020.
2025 and any year thereafter	June 1 of the fourth year before the year of the control period.

(C) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 2 allowances for any such control period to any CSAPR NO_X Ozone Season Group 2 units covered by §§ 97.811(b)(1) and 97.812(a) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 2 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by July 1 of the year of such control period.

(D) Does not provide for any change, after the submission deadlines in paragraphs (b)(9)(iii)(B) and (C) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart EEEEE of part 97 of this chapter or § 97.526(c) of this chapter;

(iv) May adopt, in addition to the definitions in § 97.802 of this chapter, one or more definitions that shall apply only to terms as used in the CSAPR NO_X Ozone Season Group 2 allowance allocation or auction provisions adopted under paragraph (b)(9)(iii) of this section;

(v) May substitute the name of the State for the term ''State'' as used in subpart EEEEE of part 97 of this chapter, to the extent the Administrator determines that such substitutions do not make substantive changes in the provisions in §§ 97.802 through 97.835 of this chapter; and

(vi) Must not include any of the requirements imposed on any unit in Indian country within the borders of the State in the provisions in §§ 97.802 through 97.835 of this chapter and must not include the provisions in §§ 97.811(b)(2) and (c)(5)(iii), 97.812(b), and 97.821(h) and (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude

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the provisions in §§ 97.802 (definitions of ''base CSAPR NO_X Ozone Season Group 2 source'', ''base CSAPR NO_X Ozone Season Group 2 unit'', ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.806(c)(2), and 97.825 of this chapter and the portions of other provisions of subpart EEEEE of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(9)(i) through (vi) of this section by December 1 of the year before the year of the deadlines for submission of allocations or auction results under paragraphs (b)(9)(iii)(B) and (C) of this section applicable to the first control period for which the State wants to replace the applicability provisions, make allocations, or hold an auction under paragraph (b)(9)(i), (ii), or (iii) of this section.

(10) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section or paragraphs (b)(1), (b)(2)(iii), and (b)(7) and (8) of this section for sources in the State—

(i) The provisions of paragraph (b)(2)(i) or (iii) of this section, as applicable, will no longer apply to sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision; and

(ii) For a State listed in § 51.121(c) of this chapter, the State's adoption of the regulations included in such approved SIP revision will satisfy with regard to the sources subject to such regulations, including any sources made subject to such regulations pursuant to paragraph (b)(9)(ii) of this section, the requirement under § 51.121(r)(2) of this chapter for the State to revise its SIP to adopt control measures with regard to such sources.

(11) Notwithstanding the provisions of paragraph (b)(10)(i) of this section—

(i) If, at the time of such approval of the State's SIP revision, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances under subpart BBBBB of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, to units in the State for a control period in any year, the provisions of subpart BBBBB of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 1 allowances, or of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances, as applicable, to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision; and

(ii) The provisions of § 97.526(c)(1) through (6) of this chapter authorizing the Administrator to remove CSAPR NO_X Ozone Season Group 1 allowances from any account where such allowances are held and to allocate and record amounts of CSAPR NO_X Ozone Season Group 2 allowances in place of any CSAPR NO_X Ozone Season Group 1 allowances that have been so removed or that have not been initially recorded, and the provisions of § 97.526(c)(7) of this chapter authorizing the use of CSAPR NO_X Ozone Season Group 2 allowances to satisfy requirements to hold CSAPR NO_X Ozone Season Group 1 allowances, will continue to apply.

(12) The following States have SIP revisions approved by the Administrator under paragraph (b)(3), (4), or (5) of this section:

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(3) of this section as replacing the CSAPR NO_X Ozone Season Group 1 allowance allocation provisions in § 97.511(a) of this chapter with regard to the State and the control period in 2016: Alabama and Missouri.

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(4) of this section as replacing the CSAPR NO_X Ozone Season Group 1 applicability provisions in § 97.504(a)(1) and (2) of this chapter or the CSAPR NO_X Ozone Season Group 1 allowance allocation provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to the State and the control period in 2017 or any subsequent year: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(5) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): [none].

(13) The following States have SIP revisions approved by the Administrator under paragraph (b)(6), (7), (8), or (9) of this section:

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(6) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): [none].

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(7) of this section as replacing the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in § 97.811(a) of this chapter with regard to the State and the control period in 2018: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(8) of this section as replacing the CSAPR NO_X Ozone Season Group 2 applicability provisions in § 97.804(a) and (b) or § 97.804(a)(1) and (2) of this chapter or the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter with regard to the State and the control period in 2019 or any subsequent year: [none].

(iv) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(9) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(7) and (8) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): [none].

■ 5. Section 52.39 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (d)(2), after the text ''2016, of'' adding the word ''the'';

■ c. In paragraph (d)(5)(i), removing the word ''paragraph'' and adding in its place the word ''paragraphs'';

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■ d. In paragraph (e)(1) introductory text, after the words ''with regard to'' adding the words ''the State and'';
■ e. In paragraph (e)(1)(ii), removing the words ''auction of'' and adding in their place the words ''auctions of'', and removing from the table heading the word ''administrator'' and adding in its place the words ''the Administrator'';
■ f. Revising paragraph (f) introductory text;
■ g. In paragraph (f)(1) introductory text, removing the text ''control period in 2017 and'' and adding in its place the text ''State and the control period in 2017 or'';
■ h. In paragraph (f)(1)(i), removing the words ''for such'' and adding in their place the words ''for any such'';
■ i. In paragraph (f)(1)(ii), removing the words ''auction of'' and adding in their place the words ''auctions of'', and removing from the table heading the word ''administrator'' and adding in its place the words ''the Administrator'';
■ j. In paragraph (f)(1)(iv), removing the text ''paragraphs (f)(2)(ii) and (iii)'' and adding in its place the text ''paragraphs (f)(1)(ii) and (iii)'';
■ k. Revising paragraphs (f)(4) and (5);
■ l. In paragraph (f)(6), removing the text ''hold an auction under paragraph (f)(1)(ii) and (iii)'' and adding in its place the text ''hold an auction under paragraph (f)(1)'';
■ m. In paragraph (g) introductory text, after the words ''with regard to'' adding the words ''the State and'';
■ n. In paragraph (g)(2), after the text ''2016, of'' adding the word ''the'';
■ o. In paragraph (g)(5)(i), removing the word ''paragraph'' and adding in its place the word ''paragraphs'';
■ p. In paragraph (h)(1) introductory text, removing the text ''control period in 2017 and'' and adding in its place the text ''State and the control period in 2017 or'';
■ q. In paragraph (h)(1)(ii), removing the words ''auction of'' and adding in their place the words ''auctions of'', and removing from the table heading the word ''administrator'' and adding in its place the words ''the Administrator'';
■ r. In paragraph (h)(2), removing the text ''hold an auction under paragraph (h)(1)(ii) and (iii)'' and adding in its place the text ''hold an auction under paragraph (h)(1)'';
■ s. Revising paragraph (i) introductory text;
■ t. In paragraph (i)(1) introductory text, removing the text ''control period in 2017 and'' and adding in its place the text ''State and the control period in 2017 or'';
■ u. In paragraph (i)(1)(ii), removing the words ''auction of'' and adding in their place the words ''auctions of'', and removing from the table heading the word ''administrator'' and adding in its place the words ''the Administrator'';
■ v. Revising paragraphs (i)(4) and (5);
■ w. In paragraph (i)(6), removing the text ''hold an auction under paragraphs (i)(1)(ii) and (iii)'' and adding in its place the text ''hold an auction under paragraph (i)(1)'';
■ x. Revising paragraph (j);
■ y. In paragraph (k), removing the words ''a State'' and adding in their place the words ''the State''; and
■ z. Adding paragraphs (l) and (m).

The revisions and additions read as follows:

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of sulfur dioxide?

* * * * *

(f) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (b) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR SO_2 Group 1 Trading Program set forth in §§ 97.602 through 97.635 of this chapter, except that the SIP revision:

* * * * *

(4) Must not include any of the requirements imposed on any unit in Indian country within the borders of the State in the provisions in §§ 97.602 through 97.635 of this chapter and must not include the provisions in §§ 97.611(b)(2) and (c)(5)(iii), 97.612(b), and 97.621(h) and (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(5) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.602 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.606(c)(2), and 97.625 of this chapter and the portions of other provisions of subpart CCCCC of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

* * * * *

(i) Notwithstanding the provisions of paragraph (a) of this section, a State listed in paragraph (c) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (c), (g), and (h) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State), regulations that are substantively identical to the provisions of the CSAPR SO_2 Group 2 Trading Program set forth in §§ 97.702 through 97.735 of this chapter, except that the SIP revision:

* * * * *

(4) Must not include any of the requirements imposed on any unit in Indian country within the borders of the State in the provisions in §§ 97.702 through 97.735 of this chapter and must not include the provisions in §§ 97.711(b)(2) and (c)(5)(iii), 97.712(b), and 97.721(h) and (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(5) Provided that, if and when any covered unit is located in Indian country within the borders of the State, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.702 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.706(c)(2), and 97.725 of this chapter and the portions of other provisions of subpart DDDDD of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions;

* * * * *

(j) Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section or paragraphs (a), (c), (g), and (h) of this section for sources in the State, the provisions of paragraph (b) or (c) of this section, as applicable, will no longer apply to sources in the State, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in any Indian country within the borders of the State, provided that if the CSAPR

Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

* * * * *

(l) The following States have SIP revisions approved by the Administrator under paragraph (d), (e), or (f) of this section:

(1) For each of the following States, the Administrator has approved a SIP revision under paragraph (d) of this section as replacing the CSAPR SO_2 Group 1 allowance allocation provisions in § 97.611(a) of this chapter with regard to the State and the control period in 2016: [none].

(2) For each of the following States, the Administrator has approved a SIP revision under paragraph (e) of this section as replacing the CSAPR SO_2 Group 1 allowance allocation provisions in §§ 97.611(a) and (b)(1) and 97.612(a) of this chapter with regard to the State and the control period in 2017 or any subsequent year: Missouri.

(3) For each of the following States, the Administrator has approved a SIP revision under paragraph (f) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): [none].

(m) The following States have SIP revisions approved by the Administrator under paragraph (g), (h), or (i) of this section:

(1) For each of the following States, the Administrator has approved a SIP revision under paragraph (g) of this section as replacing the CSAPR SO_2 Group 2 allowance allocation provisions in § 97.711(a) of this chapter with regard to the State and the control period in 2016: Alabama and Nebraska.

(2) For each of the following States, the Administrator has approved a SIP revision under paragraph (h) of this section as replacing the CSAPR SO_2 Group 2 allowance allocation provisions in §§ 97.711(a) and (b)(1) and 97.712(a) of this chapter with regard to the State and the control period in 2017 or any subsequent year: [none].

(3) For each of the following States, the Administrator has approved a SIP revision under paragraph (i) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (c), (g), and (h) of this section with regard to sources in the State (but not sources in any Indian country within the borders of the State): Alabama.

Subpart B—Alabama

■ 6. Section 52.54 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Removing paragraph (a)(3); and
■ c. Revising paragraph (b).

The revisions read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Annual Trading Program in subpart AAAAA of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan under § 52.38(a) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

■ 7. Section 52.55 is amended by:
■ a. Revising paragraph (a); and
■ b. Removing paragraph (c).

The revisions read as follows:

§ 52.55 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

(a) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR SO_2 Group 2 Trading Program in subpart DDDDD of part 97 of this chapter must comply with such requirements. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a

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revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan under § 52.39 for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

* * * * *

Subpart E—Arkansas

■ 8. Section 52.184 is revised to read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(b) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(c) Notwithstanding the provisions of paragraph (b) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (b) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart K—Florida

■ 9. Section 52.540 is amended by:

■ a. Revising paragraph (a); and

■ b. Removing and reserving paragraph (b).

The revisions read as follows:

§ 52.540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Florida and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

* * * * *

Subpart L—Georgia

§ 52.584 [Amended]

■ 10. Section 52.584 is amended by:

■ a. In paragraph (b)(1), removing the words ''Ozone Season'' and adding in their place the text ''Ozone Season Group 1''; and

■ b. In paragraph (b)(2), removing the words ''Ozone Season'' two times and adding in their place the text ''Ozone Season Group 1''.

Subpart O—Illinois

■ 11. Section 52.731 is amended by revising paragraph (b) to read as follows:

§ 52.731 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Illinois and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Illinois and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Illinois' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Illinois' SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart P—Indiana

■ 12. Section 52.789 is amended by revising paragraph (b) to read as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Indiana and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State

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of Indiana and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Indiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Indiana's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Q—Iowa

■ 13. Section 52.840 is amended by:
■ a. In paragraph (a)(1), removing the words "in part", and after the text "§ 52.38(a)" adding the words "for those sources and units"; and
■ b. Revising paragraph (b).

The revisions read as follows:

§ 52.840 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Iowa and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Iowa and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Iowa's SIP.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Iowa's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.841 [Amended]

■ 14. Section 52.841, paragraph (a) is amended by removing the words "in part", and after the text "§ 52.39" adding the words "for those sources and units".

Subpart R—Kansas

■ 15. Section 52.882 is amended by:
■ a. In paragraph (a)(1), removing the words "in part", and after the text "§ 52.38(a)" adding the words "for those sources and units";
■ b. Removing paragraph (a)(3); and
■ c. Adding paragraph (b).

The additions read as follows:

§ 52.882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Kansas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Kansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Kansas' SIP.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, if, at the time of the approval of Kansas' SIP revision described in paragraph (b)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR

NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.883 [Amended]

■ 16. Section 52.883, paragraph (a) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart S—Kentucky

■ 17. Section 52.940 is amended by revising paragraph (b) to read as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Kentucky and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Kentucky and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Kentucky's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Kentucky's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart T—Louisiana

■ 18. Section 52.984 is amended by revising paragraph (d) to read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart V—Maryland

■ 19. Section 52.1084 is amended by revising paragraph (b) to read as follows:

§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Maryland and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Maryland and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Maryland's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

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(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Maryland's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart X—Michigan

■ 20. Section 52.1186 is amended by:

■ a. In paragraph (d)(1), removing the words ''in part'', and after the text ''§ 52.38(a)'' adding the words ''for those sources and units''; and

■ b. Revising paragraph (e).

The revisions read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e)(1) The owner and operator of each source and each unit located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(3) Notwithstanding the provisions of paragraph (e)(2) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (e)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.1187 [Amended]

■ 21. Section 52.1187 is amended by:

■ a. In paragraph (c)(1), removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''; and

■ b. In paragraph (c)(2), removing the word ''Maryland's'' and adding in its place the word ''Michigan's''.

Subpart Y—Minnesota

§ 52.1240 [Amended]

■ 22. Section 52.1240, paragraph (c)(1) is amended by removing the words ''in part'', and after the text ''§ 52.38(a)'' adding the words ''for those sources and units''.

§ 52.1241 [Amended]

■ 23. Section 52.1241, paragraph (c)(1) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart Z—Mississippi

■ 24. Section 52.1284 is revised to read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(b) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(c) Notwithstanding the provisions of paragraph (b) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (b) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart AA—Missouri

■ 25. Section 52.1326 is amended by:
■ a. Removing paragraph (a)(3); and
■ b. Revising paragraph (b).

The revisions read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart CC—Nebraska

§ 52.1428 [Amended]

■ 26. Section 52.1428 is amended by:
■ a. In paragraph (a), removing the words "in part", and after the text "§ 52.38(a)" adding the words "for those sources and units"; and
■ b. Removing paragraph (c).

§ 52.1429 [Amended]

■ 27. Section 52.1429 is amended by:
■ a. In paragraph (a), removing the words "in part", and after the text "§ 52.39" adding the words "for those sources and units"; and
■ b. Removing paragraph (c).

Subpart FF—New Jersey

■ 28. Section 52.1584 is amended by revising paragraph (e) to read as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e)(1) The owner and operator of each source and each unit located in the State of New Jersey and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of New Jersey and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to New Jersey's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (e)(2) of this section, if, at the time of the approval of New Jersey's SIP revision described in paragraph (e)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart HH—New York

■ 29. Section 52.1684 is amended by:
■ a. In paragraph (a)(1), removing the words "in part", and after the text "§ 52.38(a)" adding the words "for those sources and units"; and
■ b. Revising paragraph (b).

The revisions read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of New York and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of New York and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an

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obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.1685 [Amended]

■ 30. Section 52.1685, paragraph (a) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart II—North Carolina

■ 31. Section 52.1784 is amended by:

■ a. In paragraph (a)(1), removing the words ''in part'', and after the text ''§ 52.38(a)'' adding the words ''for those sources and units'';

■ b. Revising paragraph (b)(1); and

■ c. Removing and reserving paragraph (b)(2).

The revisions read as follows:

§ 52.1784 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of North Carolina and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

* * * * *

§ 52.1785 [Amended]

■ 32. Section 52.1785, paragraph (a) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart KK—Ohio

■ 33. Section 52.1882 is amended by revising paragraph (b) to read as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Ohio and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Ohio and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Ohio's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Ohio's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart LL—Oklahoma

■ 34. Section 52.1930 is revised to read as follows:

§ 52.1930 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(b) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's SIP.

(c) Notwithstanding the provisions of paragraph (b) of this section, if, at the time of the approval of Oklahoma's SIP revision described in paragraph (b) of this section, the Administrator has already started recording any allocations

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of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart NN—Pennsylvania

■ 35. Section 52.2040 is amended by revising paragraph (b) to read as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Pennsylvania and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Pennsylvania and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Pennsylvania's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Pennsylvania's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart PP—South Carolina

■ 36. Section 52.2140 is amended by:

■ a. In paragraph (a)(1), removing the words ''in part'', and after the text ''§ 52.38(a)'' adding the words ''for those sources and units'';

■ b. Revising paragraph (b)(1); and

■ c. Removing and reserving paragraph (b)(2).

The revisions read as follows:

§ 52.2140 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of South Carolina and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

* * * * *

§ 52.2141 [Amended]

■ 37. Section 52.2141, paragraph (a) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart RR—Tennessee

■ 38. Section 52.2240 is amended by:

■ a. In paragraph (d)(1), removing the last sentence; and

■ b. Revising paragraph (e).

The revisions read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e)(1) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan under § 52.38(b), except to the extent the Administrator's approval is partial or conditional.

(3) Notwithstanding the provisions of paragraph (e)(2) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (e)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.2241 [Amended]

■ 39. Section 52.2241, paragraph (c)(1) is amended by removing the last sentence.

Subpart SS—Texas

■ 40. Section 52.2283 is amended by:

■ a. In paragraph (c)(1), removing the words ''in part'', and after the text ''§ 52.38(a)'' adding the words ''for those sources and units''; and

■ b. Revising paragraph (d).

The revisions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.2284 [Amended]

■ 41. Section 52.2284, paragraph (c)(1) is amended by removing the words ''in part'', and after the text ''§ 52.39'' adding the words ''for those sources and units''.

Subpart VV—Virginia

■ 42. Section 52.2440 is amended by revising paragraph (b) to read as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of Virginia and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Virginia and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of Virginia's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart XX—West Virginia

■ 43. Section 52.2540 is amended by revising paragraph (b) to read as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b)(1) The owner and operator of each source and each unit located in the State of West Virginia and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of West Virginia and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to West Virginia's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b), except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(3) Notwithstanding the provisions of paragraph (b)(2) of this section, if, at the time of the approval of West Virginia's SIP revision described in paragraph (b)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

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Subpart YY—Wisconsin

■ 44. Section 52.2587 is amended by:
■ a. In paragraph (d)(1), removing the words "in part", and after the text "§ 52.38(a)" adding the words "for those sources and units"; and
■ b. Revising paragraph (e).

The revisions read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e)(1) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 1 Trading Program in subpart BBBBB of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2015 and 2016.

(2) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b) for those sources and units, except to the extent the Administrator's approval is partial or conditional, provided that because the CSAPR FIP was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision. The obligation to comply with such requirements with regard to sources and units located in Indian country within the borders of the State will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(3) Notwithstanding the provisions of paragraph (e)(2) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (e)(2) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart EEEEE of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 2 allowances to units in the State for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

§ 52.2588 [Amended]

■ 45. Section 52.2588, paragraph (c)(1) is amended by removing the words "in part", and after the text "§ 52.39" adding the words "for those sources and units".

PART 78—APPEAL PROCEDURES

■ 46. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, and 7651, *et seq.*

■ 47. Section 78.1 is amended by:
■ a. Removing the text "TR" wherever it appears and adding in its place the text "CSAPR";
■ b. Revising paragraphs (a)(1) and (b)(2)(iv) and (v);
■ c. In paragraph (b)(3)(iii), after the semicolon adding the word "and";
■ d. In paragraph (b)(3)(iv), removing the semicolon and adding in its place a period;
■ e. Revising paragraph (b)(6) introductory text;
■ f. In paragraph (b)(9)(iv), after the text "§ 96.361" adding the words "of this chapter";
■ g. In paragraph (b)(12)(iv), after the text "§ 97.361" adding the words "of this chapter";
■ h. In paragraph (b)(13)(i), after the words "decision on" adding the word "the";
■ i. Revising paragraph (b)(14)(i);
■ j. In paragraphs (b)(14)(ii), (iii) and (v), after the words "Ozone Season" adding the text "Group 1";
■ k. Adding paragraph (b)(14)(viii);
■ l. In paragraphs (b)(15)(i) and (b)(16)(i), after the words "decision on" adding the word "the";
■ m. In paragraphs (b)(16)(ii), (iii), and (v), removing the text "Group 1" and adding in its place the text "Group 2"; and
■ n. Redesignating paragraph (b)(17) as paragraph (b)(18) and adding a new paragraph (b)(17).

The revisions and additions read as follows:

§ 78.1 Purpose and scope.

(a)(1)(i) This part shall govern appeals of any final decision of the Administrator under:

(A) Part 72, 73, 74, 75, 76, or 77 of this chapter.

(B) Subparts A through J of part 97 of this chapter.

(C) Subparts AA through II, AAA through III, or AAAA through IIII of part 96 of this chapter or State regulations approved under § 51.123(o)(1) or (2) or (aa)(1) or (2) of this chapter or § 51.124(o)(1) or (2) of this chapter.

(D) Subparts AA through II, AAA through III, or AAAA through IIII of part 97 of this chapter.

(E) Subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter or State regulations approved under § 52.38(a)(4) or (5) or (b)(4), (5), (6), (8), or (9) of this chapter or § 52.39(e), (f), (h), or (i) of this chapter.

(F) Subpart RR of part 98 of this chapter.

(ii) Notwithstanding paragraph (a)(1)(i) of this section, matters listed in § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed.

(iii) All references in paragraph (b) of this section and in § 78.3 to subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through IIII of part 96 of this chapter shall be read to include the comparable provisions in State regulations approved under § 51.123(o)(1) or (2) of this chapter, § 51.124(o)(1) or (2) of this chapter, and § 51.123(aa)(1) or (2) of this chapter, respectively.

(iv) All references in paragraph (b) of this section and in § 78.3 to subpart AAAAA of part 97 of this chapter, subpart BBBBB of part 97 of this chapter, subpart CCCCC of part 97 of this chapter, subpart DDDDD of part 97 of this chapter, and subpart EEEEE of part 97 of this chapter shall be read to include the comparable provisions in State regulations approved under § 52.38(a)(4) or (5) of this chapter, § 52.38(b)(4) or (5) of this chapter, § 52.39(e) or (f) of this chapter, § 52.39(h) or (i) of this chapter, and § 52.38(b)(6), (8), or (9) of this chapter, respectively.

* * * * *

(b) * * *

(2) * * *

(iv) The decision on the allocation of allowances under subpart F of part 73 of this chapter;

(v) The decision on the sale or return of allowances and transfer of proceeds

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under subpart E of part 73 of this chapter; and

* * * * *

(6) Under subparts A through J of part 97 of this chapter,

* * * * *

(14) * * *

(i) The decision on the allocation of CSAPR NO_X Ozone Season Group 1 allowances under §97.511(a)(2) and (b) of this chapter.

* * * * *

(viii) The decision on the removal of CSAPR NO_X Ozone Season Group 1 allowances from an Allowance Management System account and the allocation to such account or another account of CSAPR NO_X Ozone Season Group 2 allowances under § 97.526(c) of this chapter.

* * * * *

(17) Under subpart EEEEE of part 97 of this chapter,

(i) The decision on the allocation of CSAPR NO_X Ozone Season Group 2 allowances under §97.811(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of CSAPR NO_X Ozone Season Group 2 allowances under § 97.823 of this chapter.

(iii) The decision on the deduction of CSAPR NO_X Ozone Season Group 2 allowances under §§97.824 and 97.825 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.827 of this chapter.

(v) The adjustment of information in a submission and the decision on the deduction and transfer of CSAPR NO_X Ozone Season Group 2 allowances based on the information as adjusted under § 97.828 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.835 of this chapter.

* * * * *

■ 48. Section 78.3 is amended by:

■ a. In paragraph (a)(1) introductory text, removing the words ''of this part'';

■ b. Revising paragraph (a)(3) introductory text;

■ c. In paragraph (a)(8) introductory text and paragraph (a)(9) introductory text, after the text ''part 97'' adding the words ''of this chapter'';

■ d. Revising paragraph (a)(10) introductory text and paragraph (a)(11) introductory text;

■ e. In paragraph (b)(1), removing the words ''of this part'' two times; and

■ f. Revising paragraphs (b)(3)(i), (c)(7), and (d).

The revisions read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(3) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts A through J of part 97 of this chapter and that is appealable under § 78.1(a):

* * * * *

(10) The following persons may petition for administrative review of a decision of the Administrator that is made under subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter and that is appealable under § 78.1(a):

* * * * *

(11) The following persons may petition for administrative review of a decision of the Administrator that is made under subpart RR of part 98 of this chapter and that is appealable under § 78.1(a):

* * * * *

(b) * * *

(3) * * *

(i) Serve a copy of the petition on the Administrator and the following person (unless such person is the petitioner):

(A) The designated representative or authorized account representative, for a petition under paragraph (a)(1), (2), (10), or (11) of this section.

(B) The NO_X authorized account representative, for a petition under paragraph (a)(3) of this section.

(C) The CAIR designated representative or CAIR authorized account representative, for a petition under paragraph (a)(4), (5), (6), (7), (8), or (9) of this section.

* * * * *

(c) * * *

(7) Any revised or alternative action of the Administrator sought by the petitioner as necessary to implement the requirements, purposes, or policies of, as appropriate:

(i) Title IV of the Act.

(ii) Subparts A through J of part 97 of this chapter.

(iii) Subparts AA through II, AAA through III, or AAAA through IIII of part 96 of this chapter.

(iv) Subparts AA through II, AAA through III, or AAAA through IIII of part 97 of this chapter.

(v) Subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter.

(d) In no event shall a petition for administrative review be filed, or review be available under this part, with regard to:

(1) Actions of the Administrator under sections 112(r), 113, 114, 120, 301, and 303 of the Act.

(2) The reliance by the Administrator on:

(i) A certificate of representation submitted by a designated representative or an application for a general account submitted by an authorized account representative under the Acid Rain Program or subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter.

(ii) An account certificate of representation or an application for a general account submitted by a NO_X authorized account representative under the NO_X Budget Trading Program.

(iii) A certificate of representation submitted by a CAIR designated representative or an application for a general account submitted by a CAIR authorized account representative under subparts AA through II, AAA through III, or AAAA through IIII of part 96 of this chapter or subparts AA through II, AAA through III, or AAAA through IIII of part 97 of this chapter.

(3) Any provision or requirement of part 72, 73, 74, 75, 76, or 77 of this chapter, including the standard requirements under § 72.9 of this chapter and any emission monitoring or reporting requirements.

(4) Any provision or requirement of subparts A through J of part 97 of this chapter, including the standard requirements under § 97.6 of this chapter and any emission monitoring or reporting requirements.

(5) Any provision or requirement of subparts AA through II, AAA through III, or AAAA through IIII of part 96 of this chapter, including the standard requirements under §96.106, §96.206, or §96.306 of this chapter, respectively, and any emission monitoring or reporting requirements.

(6) Any provision or requirement of subparts AA through II, AAA through III, or AAAA through IIII of part 97 of this chapter, including the standard requirements under §97.106, §97.206, or §97.306 of this chapter, respectively, and any emission monitoring or reporting requirements.

(7) Any provision or requirement of subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter, including the standard requirements under § 97.406, § 97.506, § 97.606, § 97.706, or § 97.806 of this chapter, respectively, and any emission monitoring or reporting requirements.

(8) Any provision or requirement of subpart RR of part 98 of this chapter.

■ 49. Section 78.4 is amended by:

■ a. Revising paragraph (a)(1)(i);

■ b. In paragraph (a)(1)(ii), removing the word ''filing'' and adding in its place the word ''filings'';

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■ c. Revising paragraph (a)(1)(iii); and

■ d. In paragraphs (d), (e)(1), and (g), removing the words ''of this part''.

The revisions read as follows:

§ 78.4 Filings.

(a)(1) * * *

(i) Any filings on behalf of owners and operators of an affected unit or affected source, CSAPR NO_X Annual unit or CSAPR NO_X Annual source, CSAPR NO_X Ozone Season Group 1 unit or CSAPR NO_X Ozone Season Group 1 source, CSAPR NO_X Ozone Season Group 2 unit or CSAPR NO_X Ozone Season Group 2 source, CSAPR SO_2 Group 1 unit or CSAPR SO_2 Group 1 source, or CSAPR SO_2 Group 2 unit or CSAPR SO_2 Group 2 source shall be signed by the designated representative. Any filings on behalf of persons with an ownership interest with respect to allowances, CSAPR NO_X Annual allowances, CSAPR NO_X Ozone Season Group 1 allowances, CSAPR NO_X Ozone Season Group 2 allowances, CSAPR SO_2 Group 1 allowances, or CSAPR SO_2 Group 2 allowances in a general account shall be signed by the authorized account representative.

* * * * *

(iii) Any filings on behalf of owners and operators of a CAIR NO_X unit or CAIR NO_X source, CAIR SO_2 unit or CAIR SO_2 source, or CAIR NO_X Ozone Season unit or CAIR NO_X Ozone Season source shall be signed by the CAIR designated representative. Any filings on behalf of persons with an ownership interest with respect to CAIR NO_X allowances, CAIR SO_2 allowances, or CAIR NO_X Ozone Season allowances in a general account shall be signed by the CAIR authorized account representative.

* * * * *

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, AND CSAPR NO_X AND SO_2 TRADING PROGRAMS

■ 50. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

■ 51. The heading of part 97 is revised to read as set forth above.

Subpart E—NO_X Allowance Allocations

§ 97.40 [Amended]

■ 52. Section 97.40 is amended by removing the text ''appendix C of this part'' and adding in its place the text ''appendix C to this subpart''.

§ 97.41 [Amended]

■ 53. Section 97.41, paragraph (a) is amended by removing the text ''appendices A and B of this part'' and adding in its place the text ''appendices A and B to this subpart''.

§ 97.43 [Amended]

■ 54. Section 97.43 is amended by:

■ a. In paragraph (c)(3), removing the text ''appendix D of this part'' and adding in its place the text ''appendix D to this subpart''; and

■ b. In paragraph (c)(4), removing the text ''appendix D of this part'' two times and adding in its place the text ''appendix D to this subpart''.

Subpart AAAAA—CSAPR NO_X Annual Trading Program

■ 55. The heading of subpart AAAAA of part 97 is revised to read as set forth above.

§ 97.401 [Amended]

■ 56. Section 97.401 is amended by removing the text ''Transport Rule (TR) NO_X Annual Trading Program'' and adding in its place the text ''Cross-State Air Pollution Rule (CSAPR) NO_X Annual Trading Program''.

§§ 97.402 through 97.435 [Amended]

■ 57. Sections 97.402 through 97.435 are amended by removing the text ''TR'' wherever it appears and adding in its place the text ''CSAPR''.

■ 58. Section 97.402 is amended by:

■ a. Revising the introductory text and the definitions ''Allowable NO_X emission rate'' and ''Allowance Management System'';

■ b. In the definition ''Allowance Management System account'', removing the word ''holding'' and adding in its place the text ''auction, holding'';

■ c. Revising the definition ''Alternate designated representative'';

■ d. Adding in alphabetical order the definition ''Auction'';

■ e. In the definition ''Cogeneration system'', removing the words ''steam turbine'';

■ f. In the definition ''Commence commercial operation'', paragraph (2) introductory text, after the words ''defined in'' adding the word ''the'';

■ g. In the definition ''Common designated representative's share'', paragraph (2), removing the words ''and of the total'' and adding in their place the words ''and the total'';

■ h. Placing the newly amended definitions ''CSAPR NO_X Annual allowance'', ''CSAPR NO_X Annual allowance deduction or deduct CSAPR NO_X Annual allowances'', ''CSAPR NO_X Annual allowances held or hold CSAPR NO_4 Annual allowances'', ''CSAPR NO_X Annual emissions limitation'', ''CSAPR NO_X Annual source'', ''CSAPR NO_X Annual Trading Program'', ''CSAPR NO_X Annual unit'', ''CSAPR NO_X Ozone Season Trading Program'', ''CSAPR SO_2 Group 1 Trading Program'', and ''CSAPR SO_2 Group 2 Trading Program'' in alphabetical order in the section;

■ i. In the newly amended definition heading ''CSAPR NO_X Annual allowances held or hold CSAPR NO_4 Annual allowances'', removing the text ''NO_4'' and adding in its place the text ''NO_X'';

■ j. Removing the newly amended definition ''CSAPR NO_X Ozone Season Trading Program'';

■ k. Adding in alphabetical order the definitions ''CSAPR NO_X Ozone Season Group 1 Trading Program'' and ''CSAPR NO_X Ozone Season Group 2 Trading Program'';

■ l. Revising the newly amended definitions ''CSAPR SO_2 Group 1 Trading Program'' and ''CSAPR SO_2 Group 2 Trading Program'' and the definition ''Designated representative'';

■ m. In the definition ''Fossil fuel'', paragraph (2), removing the text ''§§'' and adding in its place the text ''§ '';

■ n. Removing the definition ''Gross electrical output'';

■ o. Revising the definitions ''Heat input'', ''Heat input rate'', and ''Heat rate'';

■ p. In the definition heading ''Maximum design heat input'', after the words ''heat input'' adding the word ''rate'';

■ q. Italicizing the words ''Annual unit'' in the newly amended definition heading ''Newly affected CSAPR NO_X Annual unit'';

■ r. Revising the definition ''Potential electrical output capacity''; and

■ s. In the definition ''Sequential use of energy'', paragraph (2), after the word ''from'' adding the word ''a''.

The revisions and additions read as follows:

§ 97.402 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym ''CSAPR'' shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym ''TR'' in place of the acronym ''CSAPR'':

* * * * *

Allowable NO_X emission rate means, for a unit, the most stringent State or

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federal NO_X emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR NO_X Annual allowances under the CSAPR NO_X Annual Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

* * * * *

Alternate designated representative means, for a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR NO_X Annual Trading Program. If the CSAPR NO_X Annual source is also subject to the Acid Rain Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

* * * * *

Auction means, with regard to CSAPR NO_X Annual allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under § 52.38(a)(4) or (5) of this chapter, of such CSAPR NO_X Annual allowances to be initially recorded in an Allowance Management System account.

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and § 52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and § 52.39(a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Designated representative means, for a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR NO_X Annual Trading Program. If the CSAPR NO_X Annual source is also subject to the Acid Rain Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

* * * * *

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

* * * * *

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

* * * * *

§ 97.403 [Amended]

■ 59. Section 97.403 is amended by:

■ a. Adding in alphabetical order the list entry ''CSAPR—Cross-State Air Pollution Rule'';

■ b. Removing the list entry ''kW—kilowatt electrical'';

■ c. Removing the list entry ''kWh—kilowatt hour'' and adding in its place the entry ''kWh—kilowatt-hour'';

■ d. Removing the list entry ''MWh—megawatt hour'' and adding in its place the entry ''MWh—megawatt-hour''; and

■ e. Adding in alphabetical order the list entries ''SIP—State implementation plan'' and ''TR—Transport Rule''.

§ 97.404 [Amended]

■ 60. Section 97.404 is amended by:

■ a. In paragraph (b)(1)(i)(B), removing the word ''electric'' and adding in its place the word ''electrical'';

■ b. In paragraph (b)(2)(ii), removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(2)(i)''; and

■ c. Italicizing the headings of paragraphs (c)(1) and (2).

§ 97.405 [Amended]

■ 61. Section 97.405, paragraph (b) is amended by italicizing the heading.

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§ 97.406 [Amended]

■ 62. Section 97.406 is amended by:
■ a. Italicizing the headings of paragraphs (c)(1) and (2) and (c)(4) through (7);
■ b. In paragraph (c)(2)(ii), after the words ''immediately after'' adding the words ''the year of'';
■ c. In paragraph (c)(4) heading, after the words ''Vintage of'' adding the text ''CSAPR NO_X Annual''; and
■ d. In paragraphs (c)(4)(i) and (ii), after the word ''allocated'' adding the words ''or auctioned''.

■ 63. Section 97.410 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a) introductory text, removing the text ''unit-set asides'' and adding in its place the text ''unit set-asides'';
■ c. In paragraphs (a)(1) through (23):
■ i. Removing the words ''annual trading'' wherever they appear and adding in their place the words ''Annual trading'';
■ ii. Removing the text ''NO_X annual new'' wherever it appears and adding in its place the word ''new''; and
■ iii. Removing the text ''NO_X annual Indian'' wherever it appears and adding in its place the word ''Indian'';
■ d. Adding and reserving paragraphs (a)(11)(vi) and (a)(16)(vi);
■ e. In paragraphs (b)(1) through (23), removing the text ''NO_X annual''; and
■ f. Revising paragraph (c).

The revisions read as follows:

§ 97.410 State NO_X Annual trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

* * * * *

(c) Each State NO_X Annual trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

■ 64. Section 97.411 is amended by:
■ a. Revising the section heading;
■ b. Italicizing the headings of paragraphs (b)(1) and (2);
■ c. In paragraph (b)(1)(iii), after the text ''November 30 of'' adding the word ''the'';
■ d. In paragraph (b)(1)(iv)(B), removing the words ''the each'' and adding in their place the word ''each'';
■ e. In paragraph (b)(2)(iii), after the text ''November 30 of'' adding the word ''the'';
■ f. In paragraph (b)(2)(iv)(B), removing the words ''the each'' and adding in their place the word ''each'';
■ g. In paragraph (c)(1)(ii), removing the text ''§ 52.38(a)(3), (4), or (5)'' and adding in its place the text ''§ 52.38(a)(4) or (5)'';
■ h. In paragraph (c)(5)(i)(B), after the text ''§ 52.38(a)(4) or (5)'' adding the words ''of this chapter'';
■ i. In paragraph (c)(5)(ii) introductory text, removing the words ''this paragraph'' and adding in their place the words ''this section'';
■ j. In paragraph (c)(5)(ii)(B), after the text ''§ 52.38(a)(4) or (5)'' adding the words ''of this chapter''; and
■ k. In paragraph (c)(5)(iii), removing the words ''this paragraph'' and adding in their place the words ''this section''.

The revision reads as follows:

§ 97.411 Timing requirements for CSAPR NO_X Annual allowance allocations.

* * * * *

■ 65. Section 97.412 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(2), removing the text ''§§ '' and adding in its place the text ''§ '';
■ c. In paragraph (a)(4)(i), removing the text ''paragraph (a)(1)(i) through (iii)'' and adding in its place the text ''paragraphs (a)(1)(i) through (iii)'';
■ d. In paragraph (a)(4)(ii), after the text ''paragraph (a)(4)(i)'' adding the words ''of this section'';
■ e. In paragraph (a)(9)(i), after the text ''November 30 of'' adding the word ''the'';
■ f. In paragraph (b)(4)(ii), after the text ''paragraph (b)(4)(i)'' adding the words ''of this section'';
■ g. In paragraph (b)(9)(i), after the text ''November 30 of'' adding the word ''the''; and
■ h. In paragraph (b)(10)(ii), after the text ''§ 52.38(a)(4) or (5)'' adding the words ''of this chapter''.

The revision reads as follows:

§ 97.412 CSAPR NO_X Annual allowance allocations to new units.

* * * * *

■ 66. Section 97.416 is amended by:
■ a. In paragraph (a)(1), removing the word ''Country'' and adding in its place the word ''country''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 97.416 Certificate of representation.

* * * * *

(c) A certificate of representation under this section that complies with the provisions of paragraph (a) of this section except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

■ 67. Section 97.420 is amended by:
■ a. Italicizing the headings of paragraphs (c)(1) through (6);
■ b. Adding paragraph (c)(1)(iv);
■ c. In paragraph (c)(2)(i) introductory text, removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ d. Adding paragraph (c)(2)(iv):
■ e. In paragraph (c)(4)(i), removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ f. In paragraph (c)(5)(iii)(D), removing the words ''authorized representative'' and adding in their place the words ''authorized account representative''; and
■ g. In paragraph (c)(5)(v), removing the word ''designated'' two times and adding in its place the words ''authorized account''.

The additions read as follows:

§ 97.420 Establishment of compliance accounts, assurance accounts, and general accounts.

* * * * *

(c) * * *

(1) * * *

(iv) An application for a general account under paragraph (c)(1) of this section that complies with the provisions of such paragraph except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification statement will be considered a complete application for a general account under such paragraph, and the certification statement included in such application for a general account will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

(2) * * *

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the acronym ''TR'' will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

* * * * *

■ 68. Section 97.421 is amended by:
■ a. Revising the section heading;
■ b. In paragraphs (c), (d), and (e), removing the word ''period'' and adding in its place the word ''periods'';
■ c. In paragraph (i), after the text ''through (12)'' removing the comma;
■ d. Revising paragraph (j); and
■ e. Redesignating paragraph (k) as paragraph (l) and adding a new paragraph (k).

The revisions and additions read as follows:

§ 97.421 Recordation of CSAPR NO_X Annual allowance allocations and auction results.

* * * * *

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(j) By February 15, 2016 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Annual source's compliance account the CSAPR NO_X Annual allowances allocated to the CSAPR NO_X Annual units at the source in accordance with § 97.412(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR NO_X Annual allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.411 or § 97.412 or with a SIP revision approved under § 52.38(a)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

* * * * *

■ 69. Section 97.422 is amended by revising the section heading to read as follows:

§ 97.422 Submission of CSAPR NO_X Annual allowance transfers.

* * * * *

■ 70. Section 97.423 is amended by:

■ a. Revising the section heading; and

■ b. In paragraph (b), after the word ''allocated'' adding the words ''or auctioned''.

The revision reads as follows:

§ 97.423 Recordation of CSAPR NO_X Annual allowance transfers.

* * * * *

■ 71. Section 97.424 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';

■ c. Revising paragraphs (c)(2)(i) and (ii); and

■ d. In paragraph (d), after the word ''allocated'' adding the words ''or auctioned''.

The revisions read as follows:

§ 97.424 Compliance with CSAPR NO_X Annual emissions limitation.

* * * * *

(c) * * *

(2) * * *

(i) Any CSAPR NO_X Annual allowances that were recorded in the compliance account pursuant to § 97.421 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR NO_X Annual allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

* * * * *

■ 72. Section 97.425 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';

■ c. In paragraph (b)(2)(iii) introductory text, removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(1)(ii)'';

■ d. In paragraph (b)(2)(iii)(B), after the words ''availability of'' adding the words ''the calculations incorporating'';

■ e. In paragraph (b)(4)(i), after the words ''established for'' removing the word ''the''; and

■ f. In paragraph (b)(6)(iii)(B), after the word ''appropriate'' removing the word ''at''.

The revision reads as follows:

§ 97.425 Compliance with CSAPR NO_X Annual assurance provisions.

* * * * *

§ 97.426 [Amended]

■ 73. Section 97.426, paragraph (b) is amended by removing the text ''97.427, or 97.428'' and adding in its place the text ''§ 97.427, or § 97.428''.

§ 97.428 [Amended]

■ 74. Section 97.428, paragraph (b) is amended by removing the text ''paragraph (a)(1)'' and adding in its place the text ''paragraph (a)''.

■ 75. Section 97.430 is amended by:

■ a. Revising paragraph (b) introductory text and paragraphs (b)(1) and (2);

■ b. In paragraph (b)(3) introductory text, removing the text ''§§ 75.4(e)(1) through (e)(4)'' and adding in its place the text ''§ 75.4(e)(1) through (4)''; and

■ c. In paragraph (b)(3)(iii), after the text ''§ 75.66'' adding the words ''of this chapter''.

The revisions read as follows:

§ 97.430 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR NO_X Annual unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the later of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the later of the following dates:

(1) January 1, 2015; or

(2) 180 calendar days after the date on which the unit commences commercial operation.

* * * * *

§ 97.431 [Amended]

■ 76. Section 97.431 is amended by:

■ a. Italicizing the headings of paragraphs (d)(1) through (3), (d)(3)(i) through (iv), (d)(3)(iv)(A) through (D), and (d)(3)(v); and

■ b. In paragraph (d)(3) introductory text, removing the text ''§§'' and adding in its place the text ''§ ''.

■ 77. Section 97.434 is amended by:

■ a. In paragraph (b), after the words ''comply with'' adding the word ''the''; and

■ b. Revising paragraphs (d)(1) and (3).

The revisions read as follows:

§ 97.434 Recordkeeping and reporting.

* * * * *

(d) * * *

(1) The designated representative shall report the NO_X mass emissions data and heat input data for a CSAPR NO_X Annual unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with the later of:

(i) The calendar quarter covering January 1, 2015 through March 31, 2015; or

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.430(b).

* * * * *

(3) For CSAPR NO_X Annual units that are also subject to the Acid Rain Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

* * * * *

§ 97.435 [Amended]

■ 78. Section 97.435 is amended by redesignating paragraphs (b)(i) through (v) as paragraphs (b)(1) through (5).

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

■ 79. The heading of subpart BBBBB of part 97 is revised to read as set forth above.

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§ 97.501 [Amended]

■ 80. Section 97.501 is amended by removing the text ''Transport Rule (TR) NO_X Ozone Season Trading Program'' and adding in its place the text ''Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 1 Trading Program''.

§§ 97.502 through 97.508 and 97.511 through 97.535 [Amended]

■ 81. Sections 97.502 through 97.508 and 97.511 through 97.535 are amended by:

■ a. Removing the text ''TR'' wherever it appears and adding in its place the text ''CSAPR''; and

■ b. After the words ''Ozone Season'' wherever they appear adding the text ''Group 1''.

■ 82. Section 97.502 is amended by:

■ a. Revising the introductory text and the definitions ''Allowable NO_X emission rate'' and ''Allowance Management System'';

■ b. In the definition ''Allowance Management System account'', removing the word ''holding'' and adding in its place the text ''auction, holding'';

■ c. Revising the definition ''Allowance transfer deadline'';

■ d. In the definition ''Alternate designated representative'', after the words ''the alternate designated representative'' removing the comma;

■ e. Adding in alphabetical order the definition ''Auction'';

■ f. In the definition ''Cogeneration system'', removing the words ''steam turbine'';

■ g. In the definition ''Commence commercial operation'', paragraph (2) introductory text, after the words ''defined in'' adding the word ''the'';

■ h. In the definition ''Common designated representative's share'', paragraph (2), removing the words ''and of the total'' and adding in their place the words ''and the total'';

■ i. Placing the newly amended definitions ''CSAPR NO_X Annual Trading Program'', ''CSAPR NO_X Ozone Season allowance'', ''CSAPR NO_X Ozone Season allowance deduction or deduct CSAPR NO_X Ozone Season allowances'', ''CSAPR NO_X Ozone Season allowances held or hold CSAPR NO_X Ozone Season allowances'', ''CSAPR NO_X Ozone Season emissions limitation'', ''CSAPR NO_X Ozone Season source'', ''CSAPR NO_X Ozone Season Trading Program'', ''CSAPR NO_X Ozone Season unit'', ''CSAPR SO_2 Group 1 Trading Program'', and ''CSAPR SO_2 Group 2 Trading Program'' in alphabetical order in the section;

■ j. Revising the newly amended definition ''CSAPR NO_X Ozone Season Group 1 Trading Program'';

■ k. Adding in alphabetical order the definitions ''CSAPR NO_X Ozone Season Group 2 allowance'' and ''CSAPR NO_X Ozone Season Group 2 Trading Program'';

■ l. Revising the newly amended definitions ''CSAPR SO_2 Group 1 Trading Program'' and ''CSAPR SO_2 Group 2 Trading Program'';

■ m. In the definition ''Designated representative'', after the words ''the designated representative'' removing the comma;

■ n. In the definition ''Fossil fuel'', paragraph (2), removing the text ''§§'' and adding in its place the text ''§ '';

■ o. Removing the definition ''Gross electrical output'';

■ p. Revising the definitions ''Heat input'', ''Heat input rate'', and ''Heat rate'';

■ q. In the definition heading ''Maximum design heat input'', after the words ''heat input'' adding the word ''rate'';

■ r. Revising the definition ''Potential electrical output capacity'';

■ s. In the definition ''Sequential use of energy'', paragraph (2), after the word ''from'' adding the word ''a''; and

■ t. Revising the definition ''State''.

The revisions and additions read as follows:

§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym ''CSAPR'' shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym ''TR'' in place of the acronym ''CSAPR'':

* * * * *

Allowable NO_X emission rate means, for a unit, the most stringent State or federal NO_X emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR NO_X Ozone Season Group 1 allowances under the CSAPR NO_X Ozone Season Group 1 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

* * * * *

Allowance transfer deadline means, for a control period in 2015 or 2016, midnight of December 1, 2015 or December 1, 2016, respectively, or for a control period in any other given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR NO_X Ozone Season Group 1 allowance transfer must be submitted for recordation in a CSAPR NO_X Ozone Season Group 1 source's compliance account in order to be available for use in complying with the source's CSAPR NO_X Ozone Season Group 1 emissions limitation for such control period in accordance with §§ 97.506 and 97.524.

* * * * *

Auction means, with regard to CSAPR NO_X Ozone Season Group 1 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under §52.38(b)(4) or (5) of this chapter, of such CSAPR NO_X Ozone Season Group 1 allowances to be initially recorded in an Allowance Management System account.

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with this subpart and § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart EEEEE of this part or § 97.526(c), or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(6), (7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and § 52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and § 52.39(a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

* * * * *

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

* * * * *

State means one of the States that is subject to the CSAPR NO_X Ozone Season Group 1 Trading Program pursuant to § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter.

* * * * *

§ 97.503 [Amended]

■ 83. Section 97.503 is amended by:
■ a. Adding in alphabetical order the list entry ''CSAPR—Cross-State Air Pollution Rule'';
■ b. Removing the list entry ''kW—kilowatt electrical'';
■ c. Removing the list entry ''kWh—kilowatt hour'' and adding in its place the entry ''kWh—kilowatt-hour'';
■ d. Removing the list entry ''MWh—megawatt hour'' and adding in its place the entry ''MWh—megawatt-hour''; and
■ e. Adding in alphabetical order the list entries ''SIP—State implementation plan'' and ''TR—Transport Rule''.

§ 97.504 [Amended]

■ 84. Section 97.504 is amended by:
■ a. In paragraph (b)(1)(i)(B), removing the word ''electric'' and adding in its place the word ''electrical'';
■ b. In paragraph (b)(2)(ii), removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(2)(i)'', and removing the text ''NO_X'' and adding in its place the text ''NO_X''; and
■ c. Italicizing the headings of paragraphs (c)(1) and (2).

§ 97.505 [Amended]

■ 85. Section 97.505, paragraph (b) is amended by italicizing the heading.

§ 97.506 [Amended]

■ 86. Section 97.506 is amended by:
■ a. Italicizing the headings of paragraphs (c), (c)(1) and (2), and (c)(4) through (7);
■ b. In paragraph (c)(2)(ii), after the words ''immediately after'' adding the words ''the year of'';
■ c. In paragraph (c)(3)(i), after the paragraph designation ''(i)'' adding a space;
■ d. In paragraph (c)(4) heading, after the words ''Vintage of'' adding the text ''CSAPR NO_X Ozone Season Group 1''; and
■ e. In paragraphs (c)(4)(i) and (ii), after the word ''allocated'' adding the words ''or auctioned''.

■ 87. Section 97.510 is amended by:
■ a. Revising the section heading;
■ b. Revising paragraph (a) introductory text;
■ c. In paragraphs (a)(1) through (25):
■ i. Removing the words ''ozone season trading'' wherever they appear and adding in their place the text ''Ozone Season Group 1 trading'';
■ ii. Removing the text ''NO_X ozone season new'' wherever it appears and adding in its place the word ''new''; and
■ iii. Removing the text ''NO_X ozone season Indian'' wherever it appears and adding in its place the word ''Indian'';
■ d. Adding and reserving paragraphs (a)(2)(vi), (a)(13)(vi), (a)(17)(vi), and (a)(18)(vi);
■ e. Revising paragraph (b) introductory text;
■ f. In paragraphs (b)(1) through (25), removing the text ''NO_X ozone season''; and
■ g. Revising paragraph (c).

The revisions read as follows:

§ 97.510 State NO_X Ozone Season Group 1 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State NO_X Ozone Season Group 1 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 1 allowances for the control periods in 2015 and thereafter are as follows:

* * * * *

(b) The States' variability limits for the State NO_X Ozone Season Group 1 trading budgets for the control periods in 2017 and thereafter are as follows:

* * * * *

(c) Each State NO_X Ozone Season Group 1 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

■ 88. Section 97.511 is amended by:
■ a. Revising the section heading;
■ b. Italicizing the headings of paragraphs (b)(1) and (2);
■ c. Revising paragraph (b)(1)(iii);
■ d. In paragraph (b)(1)(iv)(B), removing the words ''the each'' and adding in their place the word ''each'', and revising the second sentence;
■ e. Revising paragraph (b)(2)(iii);
■ f. In paragraph (b)(2)(iv)(B), removing the words ''the each'' and adding in

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their place the word ''each'', revising the second sentence, and after the newly revised second sentence adding a paragraph break before the paragraph designation ''(v)'' for the following paragraph (b)(2)(v);

■ g. In paragraph (c)(1)(ii), removing the text ''§ 52.38(b)(3), (4), or (5)'' and adding in its place the text ''§ 52.38(b)(4) or (5)'', and removing the text ''January 1'' and adding in its place the text ''May 1'';

■ h. In paragraph (c)(5)(i)(B), after the text ''§ 52.38(b)(4) or (5)'' adding the words ''of this chapter'', and removing the word ''Annual'' and adding in its place the text ''Ozone Season Group 1'';

■ i. In paragraph (c)(5)(ii) introductory text, removing the words ''this paragraph'' and adding in their place the words ''this section'';

■ j. In paragraph (c)(5)(ii)(B), after the text ''§ 52.38(b)(4) or (5)'' adding the words ''of this chapter''; and

■ k. In paragraph (c)(5)(iii), removing the words ''this paragraph'' and adding in their place the words ''this section''.

The revisions read as follows:

§ 97.511 Timing requirements for CSAPR NO_X Ozone Season Group 1 allowance allocations.

* * * * *

(b) * * *

(1) * * *

(iii)(A) If the new unit set-aside for the control period in 2015 or 2016 contains any CSAPR NO_X Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 1 units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period.

(B) If the new unit set-aside for the control period in 2017 or any subsequent year contains any CSAPR NO_X Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) * * *

(B) * * * By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii)(A) of this section, or by February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii)(B) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

* * * * *

(2) * * *

(iii)(A) If the Indian country new unit set-aside for the control period in 2015 or 2016 contains any CSAPR NO_X Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 1 units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period.

(B) If the Indian country new unit set-aside for the control period in 2017 or any subsequent year contains any CSAPR NO_X Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) * * *

(B) * * * By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(A) of this section, or by February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

* * * * *

■ 89. Section 97.512 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(2), removing the text ''§§ '' and adding in its place the text ''§ '';

■ c. In paragraph (a)(4)(i), removing the text ''paragraph (a)(1)(i) through (iii)'' and adding in its place the text ''paragraphs (a)(1)(i) through (iii)'';

■ d. In paragraph (a)(4)(ii), after the text ''paragraph (a)(4)(i)'' adding the words ''of this section'';

■ e. Revising paragraph (a)(9)(i);

■ f. In paragraph (b)(4)(ii), after the text ''paragraph (b)(4)(i)'' adding the words ''of this section'';

■ g. Revising paragraph (b)(9)(i); and

■ h. In paragraph (b)(10)(ii), after the text ''§ 52.38(b)(4) or (5)'' adding the words ''of this chapter''.

The revisions read as follows:

§ 97.512 CSAPR NO_X Ozone Season Group 1 allowance allocations to new units.

(a) * * *

(9) * * *

(i)(A) For the control period in 2015 or 2016, the Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(1)(ii) for the unit for such control period;

(B) For the control period in 2017 or any subsequent year, the Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(1)(ii) for the unit for such control period;

* * * * *

(b) * * *

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(9) * * *

(i)(A) For the control period in 2015 or 2016, the Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(2)(ii) for the unit for such control period;

(B) For the control period in 2017 or any subsequent year, the Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(2)(ii) for the unit for such control period;

* * * * *

■ 90. Section 97.516 is amended by:

■ a. In paragraph (a)(1), removing the word ''Country'' and adding in its place the word ''country''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 97.516 Certificate of representation.

* * * * *

(c) A certificate of representation under this section that complies with the provisions of paragraph (a) of this section except that it contains the phrase ''TR NO_X Ozone Season'' in place of the phrase ''CSAPR NO_X Ozone Season Group 1'' in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 1'' appeared in place of the phrase ''TR NO_X Ozone Season''.

■ 91. Section 97.520 is amended by:

■ a. Italicizing the headings of paragraphs (c)(1) through (6);

■ b. Adding paragraph (c)(1)(iv);

■ c. In paragraph (c)(2)(i) introductory text, removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';

■ d. Adding paragraph (c)(2)(iv);

■ e. In paragraph (c)(4)(i), removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';

■ f. In paragraph (c)(5)(iii)(D), removing the words ''authorized representative'' and adding in their place the words ''authorized account representative''; and

■ g. In paragraph (c)(5)(v), removing the word ''designated'' two times and adding in its place the words ''authorized account''.

The additions read as follows:

§ 97.520 Establishment of compliance accounts, assurance accounts, and general accounts.

* * * * *

(c) * * *

(1) * * *

(iv) An application for a general account under paragraph (c)(1) of this section that complies with the provisions of such paragraph except that it contains the phrase ''TR NO_X Ozone Season'' in place of the phrase ''CSAPR NO_X Ozone Season Group 1'' in the required certification statement will be considered a complete application for a general account under such paragraph, and the certification statement included in such application for a general account will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 1'' appeared in place of the phrase ''TR NO_X Ozone Season''.

(2) * * *

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the phrase ''TR NO_X Ozone Season'' will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 1'' appeared in place of the phrase ''TR NO_X Ozone Season''.

* * * * *

■ 92. Section 97.521 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (c);

■ c. In paragraphs (d) and (e), removing the word ''period'' and adding in its place the word ''periods'';

■ d. Revising paragraphs (i) and (j); and

■ e. Redesignating paragraph (k) as paragraph (l) and adding a new paragraph (k).

The revisions and additions read as follows:

§ 97.521 Recordation of CSAPR NO_X Ozone Season Group 1 allowance allocations and auction results.

* * * * *

(c) By January 9, 2017, the Administrator will record in each CSAPR NO_X Ozone Season Group 1 source's compliance account the CSAPR NO_X Ozone Season Group 1 allowances allocated to the CSAPR NO_X Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 1 allowances auctioned to CSAPR NO_X Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control periods in 2017 and 2018.

* * * * *

(i)(1) By November 15, 2015 and November 15, 2016, the Administrator will record in each CSAPR NO_X Ozone Season Group 1 source's compliance account the CSAPR NO_X Ozone Season Group 1 allowances allocated to the CSAPR NO_X Ozone Season Group 1 units at the source in accordance with § 97.512(a)(9) through (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(2) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 1 source's compliance account the CSAPR NO_X Ozone Season Group 1 allowances allocated to the CSAPR NO_X Ozone Season Group 1 units at the source in accordance with § 97.512(a)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j)(1) By November 15, 2015 and November 15, 2016, the Administrator will record in each CSAPR NO_X Ozone Season Group 1 source's compliance account the CSAPR NO_X Ozone Season Group 1 allowances allocated to the CSAPR NO_X Ozone Season Group 1 units at the source in accordance with § 97.512(b)(9) through (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(2) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 1 source's compliance account the CSAPR NO_X Ozone Season Group 1 allowances allocated to the CSAPR NO_X Ozone Season Group 1 units at the source in accordance with § 97.512(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR NO_X Ozone Season Group 1 allowances

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to a recipient is made by or are submitted to the Administrator in accordance with § 97.511 or § 97.512 or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

* * * * *

■ 93. Section 97.522 is amended by revising the section heading to read as follows:

§ 97.522 Submission of CSAPR NO_X Ozone Season Group 1 allowance transfers.

* * * * *

■ 94. Section 97.523 is amended by:

■ a. Revising the section heading; and

■ b. In paragraph (b), after the word ''allocated'' adding the words ''or auctioned''.

The revision reads as follows:

§ 97.523 Recordation of CSAPR NO_X Ozone Season Group 1 allowance transfers.

* * * * *

■ 95. Section 97.524 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';

■ c. Revising paragraphs (c)(2)(i) and (ii) ; and

■ d. In paragraph (d), after the word ''allocated'' adding the words ''or auctioned''.

The revisions read as follows:

§ 97.524 Compliance with CSAPR NO_X Ozone Season Group 1 emissions limitation.

* * * * *

(c) * * *

(2) * * *

(i) Any CSAPR NO_X Ozone Season Group 1 allowances that were recorded in the compliance account pursuant to § 97.521 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR NO_X Ozone Season Group 1 allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

* * * * *

■ 96. Section 97.525 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';

■ c. In paragraph (b)(2)(iii) introductory text, removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(1)(ii)'';

■ d. In paragraph (b)(2)(iii)(B), after the words ''availability of'' adding the words ''the calculations incorporating'';

■ e. In paragraph (b)(4)(i), after the words ''established for'' removing the word ''the''; and

■ f. In paragraph (b)(6)(iii)(B), after the word ''appropriate'' removing the word ''at''.

The revision reads as follows:

§ 97.525 Compliance with CSAPR NO_X Ozone Season Group 1 assurance provisions.

* * * * *

■ 97. Section 97.526 is amended by:

■ a. In paragraph (b), removing the text ''§ 97.528'' and adding in its place the text ''§ 97.528 or removed under paragraph (c) of this section''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 97.526 Banking.

* * * * *

(c) *Replacement of CSAPR NO_X Ozone Season Group 1 allowances with CSAPR NO_X Ozone Season Group 2 allowances.* Notwithstanding any other provision of this subpart or any provision of a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, the Administrator will remove CSAPR NO_X Ozone Season Group 1 allowances from compliance accounts and general accounts and allocate in their place amounts of CSAPR NO_X Ozone Season Group 2 allowances as provided in paragraphs (c)(1) through (5) of this section and will record CSAPR NO_X Ozone Season Group 2 allowances in lieu of initially recording CSAPR NO_X Ozone Season Group 1 allowances as provided in paragraph (c)(6) of this section.

(1) As soon as practicable after the completion of deductions under § 97.524 for the control period in 2016, but not later than March 1, 2018, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 1 allowance transfers submitted under § 97.522 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account except a compliance account for a CSAPR NO_X Ozone Season Group 1 source located in a State listed in § 52.38(b)(2)(i) of this chapter or Indian country within the borders of such a State:

(i) The Administrator will remove all CSAPR NO_X Ozone Season Group 1 allowances allocated for the control periods in 2015 and 2016 from each such account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the sum of all CSAPR NO_X Ozone Season Group 1 allowances removed from all such accounts under paragraph (c)(1)(i) of this section divided by the product of 1.5 times the sum of the variability limits for the control period in 2017 set forth in § 97.810(b) for all States except a State listed in § 52.38(b)(2)(i) of this chapter.

(iii) The Administrator will allocate to and record in each such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017, where such amount is determined as the quotient of the number of CSAPR NO_X Ozone Season Group 1 allowances removed from such account under paragraph (c)(1)(i) of this section divided by the conversion factor determined under paragraph (c)(1)(ii) of this section, rounded up to the nearest whole allowance, except as provided in paragraphs (c)(4) and (5) of this section.

(2) As soon as practicable after approval of a SIP revision under § 52.38(b)(6) of this chapter for a State listed in § 52.38(b)(2)(i) of this chapter, but not later than the allowance transfer deadline defined under § 97.802 for the initial control period described with regard to such SIP revision in § 52.38(b)(6)(ii)(A) of this chapter, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 1 allowance transfers submitted under § 97.522 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account, unless otherwise provided in such approval of the SIP revision:

(i) The Administrator will remove from each such account all CSAPR NO_X Ozone Season Group 1 allowances for such initial control period and each subsequent control period that were allocated to units located in such State under this subpart or that were allocated or auctioned to any entity under a SIP revision for such State approved by the Administrator under § 52.38(b)(4) or (5) of this chapter, whether such CSAPR NO_X Ozone Season Group 1 allowances were initially recorded in such account or were transferred to such account from another account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the NO_X Ozone Season Group 1 trading budget set forth for such State in § 97.510(a) divided by the NO_X Ozone Season Group 2 trading budget set forth for such State in § 97.810(a).

(iii) The Administrator will allocate to and record in each such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for each control

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period for which CSAPR NO_X Ozone Season Group 1 allowances were removed from such account, where each such amount is determined as the quotient of the number of CSAPR NO_X Ozone Season Group 1 allowances for such control period removed from such account under paragraph (c)(2)(i) of this section divided by the conversion factor determined under paragraph (c)(2)(ii) of this section, rounded up to the nearest whole allowance, except as provided in paragraphs (c)(4) and (5) of this section.

(3) As soon as practicable after approval of a SIP revision under § 52.38(b)(6) of this chapter for a State listed in § 52.38(b)(2)(i) of this chapter, but not before the completion of deductions under § 97.524 for the control period before the initial control period described with regard to such SIP revision in § 52.38(b)(6)(ii)(A) of this chapter and not later than the allowance transfer deadline defined under § 97.802 for such initial control period, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 1 allowance transfers submitted under § 97.522 and, before resuming acceptance of such transfers, will take the following actions with regard to every compliance account for a CSAPR NO_X Ozone Season Group 1 source located in such State, provided that if the provisions of § 52.38(b)(2)(i) of this chapter or a SIP revision approved under § 52.38(b)(5) of this chapter will no longer apply to any source in any State or Indian country within the borders of any State with regard to emissions occurring in such initial control period or any subsequent control period, the Administrator instead will permanently end acceptance of CSAPR NO_X Ozone Season Group 1 allowance transfers submitted under § 97.522 and will take the following actions with regard to every general account and every compliance account:

(i) The Administrator will remove from each such account all CSAPR NO_X Ozone Season Group 1 allowances allocated for all control periods before such initial control period.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the sum of all CSAPR NO_X Ozone Season Group 1 allowances removed from all such accounts under paragraph (c)(3)(i) of this section divided by the product of 1.5 times the variability limit for such initial control period set forth for such State in § 97.810(b).

(iii) The Administrator will allocate to and record in each such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for such initial control period, where such amount is determined as the quotient of the number of CSAPR NO_X Ozone Season Group 1 allowances removed from such account under paragraph (c)(3)(i) of this section divided by the conversion factor determined under paragraph (c)(3)(ii) of this section, rounded up to the nearest whole allowance, except as provided in paragraphs (c)(4) and (5) of this section.

(4) Where, pursuant to paragraph (c)(1)(i), (c)(2)(i), or (c)(3)(i) of this section, the Administrator removes CSAPR NO_X Ozone Season Group 1 allowances from the compliance account for a source located in a State not listed in § 52.38(b)(2)(iii) of this chapter or Indian country within the borders of such a State, the Administrator will not record CSAPR NO_X Ozone Season Group 2 allowances in that account but instead will allocate to and record in another compliance account or general account CSAPR NO_X Ozone Season Group 2 allowances for the control periods and in the amounts determined in accordance with paragraph (c)(1)(iii), (c)(2)(iii), or (c)(3)(iii) of this section, respectively, provided that the designated representative for such source identifies such other account in a submission to the Administrator and further provided that any compliance account identified in such a submission is for a source located in a State listed in § 52.38(b)(2)(iii) of this chapter or Indian country within the borders of such a State.

(5)(i) In computing any amounts of CSAPR NO_X Ozone Season Group 2 allowances to be allocated to and recorded in general accounts under paragraph (c)(1)(iii), (c)(2)(iii), or (c)(3)(iii) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(ii) Following a computation for a group of general accounts in accordance with paragraph (c)(5)(i) of this section, the Administrator will allocate to and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 2 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 1 allowances removed from such individual accounts under paragraph (c)(1)(i), (c)(2)(i), or (c)(3)(i) of this section, as applicable.

(iii) In determining the proportional shares under paragraph (c)(5)(ii) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 2 allowances computed for such group of accounts in accordance with paragraph (c)(5)(i) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 2 allowances allocated to some individual accounts to equal zero.

(6) After the Administrator has carried out the procedures set forth in paragraph (c)(1), (2), or (3) of this section, upon any determination that would otherwise result in the initial recordation of any CSAPR NO_X Ozone Season Group 1 allowances in any account, where if such allowances had been recorded before the Administrator had carried out such procedures the allowances would have been removed from such account under paragraph (c)(1)(i), (c)(2)(i), or (c)(3)(i) of this section, respectively, the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will record CSAPR NO_X Ozone Season Group 2 allowances for the control periods and in the amounts determined in accordance with paragraph (c)(1)(iii), (c)(2)(iii), or (c)(3)(iii) of this section, respectively, in such account or another account identified in accordance with paragraph (c)(4) of this section.

(7) Notwithstanding any other provision of this subpart or subpart EEEEE of this part, CSAPR NO_X Ozone Season Group 2 allowances may be used to satisfy requirements to hold CSAPR NO_X Ozone Season Group 1 allowances under this subpart as follows, provided that nothing in this paragraph alters the time as of which any such allowance holding requirement must be met or limits any consequence of a failure to timely meet any such allowance holding requirement:

(i) After the Administrator has carried out the procedures set forth in paragraph (c)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 1 unit in a State listed in § 52.38(b)(2)(iii) of this chapter or Indian country within the borders of such a State may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017, where such amount of CSAPR NO_X Ozone Season Group 2 allowances is computed as the quotient of such given number of CSAPR NO_X

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Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (c)(1)(ii) of this section, rounded up to the nearest whole allowance.

(ii) After the Administrator has carried out the procedures set forth in paragraph (c)(3) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 1 unit in a State listed in § 52.38(b)(2)(i) of this chapter may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for a control period before the initial control period described with regard to the State's SIP revision in § 52.38(b)(6)(ii)(A) of this chapter by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 2 allowances for such initial control period or any previous control period, where such amount of CSAPR NO_X Ozone Season Group 2 allowances is computed as the quotient of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (c)(3)(ii) of this section, rounded up to the nearest whole allowance.

§ 97.528 [Amended]

■ 98. Section 97.528, paragraph (b) is amended by removing the text ''paragraph (a)(1)'' and adding in its place the text ''paragraph (a)''.

■ 99. Section 97.530 is amended by:

■ a. Revising paragraph (b) introductory text and paragraphs (b)(1) through (3);

■ b. In paragraph (b)(4) introductory text, removing the text ''§§ 75.4 (e)(1) through (e)(4)'' and adding in its place the text ''§ 75.4 (e)(1) through (4)''; and

■ c. In paragraph (b)(4)(iii), after the text ''§ 75.66'' adding the words ''of this chapter''.

The revisions read as follows:

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 1 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the latest of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the latest of the following dates:

(1) May 1, 2015;

(2) 180 calendar days after the date on which the unit commences commercial operation; or

(3) Where data for the unit are reported on a control period basis under § 97.534(d)(1)(ii)(B), and where the compliance date under paragraph (b)(2) of this section is not in a month from May through September, May 1 immediately after the compliance date under paragraph (b)(2) of this section.

* * * * *

§ 97.531 [Amended]

■ 100. Section 97.531 is amended by:

■ a. Italicizing the headings of paragraphs (d)(1) through (3), (d)(3)(i) through (iv), (d)(3)(iv)(A) through (D), and (d)(3)(v);

■ b. In paragraph (d)(3) introductory text, removing the text ''§§ '' and adding in its place the text ''§ ''; and

■ c. Redesignating paragraphs (d)(3)(v)(A)(1) through (5) as paragraphs (d)(3)(v)(A)(*1*) through (*5*).

■ 101. Section 97.534 is amended by:

■ a. In paragraph (b), after the words ''comply with'' adding the word ''the'';

■ b. Revising paragraphs (d)(1) and (2);

■ c. Redesignating paragraph (d)(6) as paragraph (d)(5)(ii); and

■ d. In paragraph (e)(3), removing the text ''paragraph (d)(2)(ii)'' and adding in its place the text ''paragraph (d)(1)(ii)(B)''.

The revisions read as follows:

§ 97.534 Recordkeeping and reporting.

* * * * *

(d) * * *

(1)(i) If a CSAPR NO_X Ozone Season Group 1 unit is subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program or if the owner or operator of such unit chooses to report on an annual basis under this subpart, then the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year.

(ii) If a CSAPR NO_X Ozone Season Group 1 unit is not subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program, then the designated representative shall either:

(A) Meet the requirements of subpart H of part 75 of this chapter for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year in accordance with paragraph (d)(1)(i) of this section; or

(B) Meet the requirements of subpart H of part 75 of this chapter (including the requirements in § 75.74(c) of this chapter) for such unit for the control period and report the NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year.

(2) The designated representative shall report the NO_X mass emissions data and heat input data for a CSAPR NO_X Ozone Season Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter indicated under paragraph (d)(1) of this section beginning by the latest of:

(i) The calendar quarter covering May 1, 2015 through June 30, 2015;

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b); or

(iii) For a unit that reports on a control period basis under paragraph (d)(1)(ii)(B) of this section, if the calendar quarter under paragraph (d)(2)(ii) of this section does not include a month from May through September, the calendar quarter covering May 1 through June 30 immediately after the calendar quarter under paragraph (d)(2)(ii) of this section.

* * * * *

§ 97.535 [Amended]

■ 102. Section 97.535 is amended by:

■ a. Redesignating paragraphs (b)(i) through (v) as paragraphs (b)(1) through (5); and

■ b. In the newly redesignated paragraph (b)(4), removing the colon and adding in its place a semicolon.

Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program

■ 103. The heading of subpart CCCCC of part 97 is revised to read as set forth above.

§ 97.601 [Amended]

■ 104. Section 97.601 is amended by removing the text ''Transport Rule (TR) SO_2 Group 1 Trading Program'' and adding in its place the text ''Cross-State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program''.

§§ 97.602 through 97.635 [Amended]

■ 105. Sections 97.602 through 97.635 are amended by removing the text ''TR'' wherever it appears and adding in its place the text ''CSAPR''.

■ 106. Section 97.602 is amended by:

■ a. Revising the introductory text and the definitions ''Allowable SO_2 emission rate'' and ''Allowance Management System'';

■ b. In the definition ''Allowance Management System account'',

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removing the word ''holding'' and adding in its place the text ''auction, holding'';

■ c. Revising the definition ''Alternate designated representative'';

■ d. Adding in alphabetical order the definition ''Auction'';

■ e. In the definition ''Cogeneration system'', removing the words ''steam turbine'';

■ f. In the definition ''Commence commercial operation'', paragraph (2) introductory text, after the words ''defined in'' adding the word ''the'';

■ g. In the definition ''Common designated representative's share'', paragraph (2), removing the words ''and of the total'' and adding in their place the words ''and the total'';

■ h. Placing the newly amended definitions ''CSAPR NO_X Annual Trading Program'', ''CSAPR NO_X Ozone Season Trading Program'', ''CSAPR SO_2 Group 1 allowance'', ''CSAPR SO_2 Group 1 allowance deduction or deduct CSAPR SO_2 Group 1 allowances'', ''CSAPR SO_2 Group 1 allowances held or hold CSAPR SO_2 Group 1 allowances'', ''CSAPR SO_2 Group 1 emissions limitation'', ''CSAPR SO_2 Group 1 source'', ''CSAPR SO_2 Group 1 Trading Program'', and ''CSAPR SO_2 Group 1 unit'' in alphabetical order in the section;

■ i. Removing the newly amended definition ''CSAPR NO_X Ozone Season Trading Program'';

■ j. Adding in alphabetical order the definitions ''CSAPR NO_X Ozone Season Group 1 Trading Program'' and ''CSAPR NO_X Ozone Season Group 2 Trading Program'';

■ k. Revising the newly amended definition ''CSAPR SO_2 Group 1 Trading Program'' and the definition ''Designated representative'';

■ l. In the definition ''Fossil fuel'', paragraph (2), removing the text ''§§'' and adding in its place the text ''§ '';

■ m. Removing the definition ''Gross electrical output'';

■ n. Revising the definitions ''Heat input'', ''Heat input rate'', and ''Heat rate'';

■ o. In the definition heading ''Maximum design heat input'', after the words ''heat input'' adding the word ''rate'';

■ p. Revising the definition ''Potential electrical output capacity'';

■ q. In the definition ''Sequential use of energy'', paragraph (2), after the word ''from'' adding the word ''a''; and

■ r. Revising the definition ''State''.

The revisions and additions read as follows:

§ 97.602 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym ''CSAPR'' shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym ''TR'' in place of the acronym ''CSAPR'':

* * * * *

Allowable SO_2 emission rate means, for a unit, the most stringent State or federal SO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR SO_2 Group 1 allowances under the CSAPR SO_2 Group 1 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

* * * * *

Alternate designated representative means, for a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR SO_2 Group 1 Trading Program. If the CSAPR SO_2 Group 1 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

* * * * *

Auction means, with regard to CSAPR SO_2 Group 1 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under § 52.39(e) or (f) of this chapter, of such CSAPR SO_2 Group 1 allowances to be initially recorded in an Allowance Management System account.

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and § 52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with this subpart and § 52.39(a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

Designated representative means, for a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR SO_2 Group 1 Trading Program. If the CSAPR SO_2 Group 1 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

* * * * *

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit

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operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

* * * * *

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

* * * * *

State means one of the States that is subject to the CSAPR SO_2 Group 1 Trading Program pursuant to § 52.39(a), (b), (d) through (f), and (j) through (l) of this chapter.

* * * * *

§ 97.603 [Amended]

■ 107. Section 97.603 is amended by:
■ a. Adding in alphabetical order the list entry ''CSAPR—Cross-State Air Pollution Rule'';
■ b. Removing the list entry ''kW—kilowatt electrical'';
■ c. Removing the list entry ''kWh—kilowatt hour'' and adding in its place the entry ''kWh—kilowatt-hour'';
■ d. Removing the list entry ''MWh—megawatt hour'' and adding in its place the entry ''MWh—megawatt-hour''; and
■ e. Adding in alphabetical order the list entries ''SIP—State implementation plan'' and ''TR—Transport Rule''.

§ 97.604 [Amended]

■ 108. Section 97.604 is amended by:
■ a. In paragraph (b)(1)(i)(B), removing the word ''electric'' and adding in its place the word ''electrical'';
■ b. In paragraph (b)(2)(ii), removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(2)(i)''; and
■ c. Italicizing the headings of paragraphs (c)(1) and (2).

§ 97.605 [Amended]

■ 109. Section 97.605, paragraph (b) is amended by italicizing the heading.

§ 97.606 [Amended]

■ 110. Section 97.606 is amended by:
■ a. Italicizing the headings of paragraphs (c)(1) and (2) and (c)(4) through (7);
■ b. In paragraph (c)(2)(ii), after the words ''immediately after'' adding the words ''the year of'';
■ c. In paragraph (c)(4) heading, after the words ''Vintage of'' adding the text ''CSAPR SO_2 Group 1'';
■ d. In paragraphs (c)(4)(i) and (ii), after the word ''allocated'' adding the words ''or auctioned''; and
■ e. In paragraph (d)(2), removing the text ''subpart H'' and adding in its place the text ''subpart B''.
■ 111. Section 97.610 is amended by:
■ a. Revising the section heading;
■ b. Revising paragraph (a) introductory text;
■ c. In paragraphs (a)(1) through (16):
■ i. Removing the word ''trading'' wherever it appears and adding in its place the text ''Group 1 trading'';
■ ii. Removing the text ''SO_2 new'' wherever it appears and adding in its place the word ''new''; and
■ iii. Removing the text ''SO_2 Indian'' wherever it appears and adding in its place the word ''Indian'';
■ d. Adding and reserving paragraphs (a)(2)(vi) and (a)(11)(vi);
■ e. In paragraphs (b)(1) through (16), removing the text ''SO_2''; and
■ f. Revising paragraph (c).

The revisions read as follows:

§ 97.610 State SO_2 Group 1 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State SO_2 Group 1 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR SO_2 Group 1 allowances for the control periods in 2015 and thereafter are as follows:

* * * * *

(c) Each State SO_2 Group 1 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

■ 112. Section 97.611 is amended by:
■ a. Revising the section heading;
■ b. Italicizing the headings of paragraphs (b)(1) and (2);
■ c. In paragraphs (b)(1)(iii) and (b)(2)(iii), after the text ''November 30 of'' adding the word ''the'';
■ d. In paragraph (b)(2)(v), removing the text ''NO_X Annual'' and adding in its place the text ''SO_2 Group 1'';
■ e. In paragraph (c)(1)(ii), removing the text ''§ 52.39(d), (e), or (f)'' and adding in its place the text ''§ 52.39(e) or (f)'';
■ f. In paragraph (c)(5)(i)(B), after the text ''§ 52.39(e) or (f)'' adding the words ''of this chapter'';
■ g. In paragraph (c)(5)(ii) introductory text, removing the words ''this paragraph'' and adding in their place the words ''this section'';
■ h. In paragraph (c)(5)(ii)(B), after the text ''§ 52.39(e) or (f)'' adding the words ''of this chapter''; and
■ i. In paragraph (c)(5)(iii), removing the words ''this paragraph'' and adding in their place the words ''this section''.

The revision reads as follows:

§ 97.611 Timing requirements for CSAPR SO_2 Group 1 allowance allocations.

* * * * *

■ 113. Section 97.612 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(2), removing the text ''§§ '' and adding in its place the text ''§ '';
■ c. In paragraph (a)(4)(i), removing the text ''paragraph (a)(1)(i) through (iii)'' and adding in its place the text ''paragraphs (a)(1)(i) through (iii)'';
■ d. In paragraph (a)(4)(ii), after the text ''paragraph (a)(4)(i)'' adding the words ''of this section'';
■ e. In paragraph (a)(9)(i), after the text ''November 30 of'' adding the word ''the'';
■ f. In paragraph (b)(4)(ii), after the text ''paragraph (b)(4)(i)'' adding the words ''of this section'';
■ g. In paragraph (b)(9)(i), after the text ''November 30 of'' adding the word ''the'';
■ h. In paragraph (b)(10)(ii), removing the text ''§ 52.39(d), (e), or (f)'' and adding in its place the text ''§ 52.39(e) or (f)''; and
■ i. In paragraph (b)(11), after the text ''paragraphs (b)(9), (10) and (12)'' adding the words ''of this section''.

The revision reads as follows:

§ 97.612 CSAPR SO_2 Group 1 allowance allocations to new units.

* * * * *

■ 114. Section 97.616 is amended by:
■ a. In paragraph (a)(1), removing the word ''Country'' and adding in its place the word ''country''; and
■ b. Adding paragraph (c).

The additions read as follows:

§ 97.616 Certificate of representation.

* * * * *

(c) A certificate of representation under this section that complies with the provisions of paragraph (a) of this section except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification

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statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

■ 115. Section 97.620 is amended by:
■ a. Italicizing the headings of paragraphs (c)(1) through (6);
■ b. Adding paragraph (c)(1)(iv);
■ c. In paragraph (c)(2)(i) introductory text, removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ d. Adding paragraph (c)(2)(iv);
■ e. In paragraph (c)(4)(i), removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ f. In paragraph (c)(5)(iii)(D), removing the words ''authorized representative'' and adding in their place the words ''authorized account representative''; and
■ g. In paragraph (c)(5)(v), removing the word ''designated'' two times and adding in its place the words ''authorized account''.

The additions read as follows:

§ 97.620 Establishment of compliance accounts, assurance accounts, and general accounts.

* * * * *

(c) * * *

(1) * * *

(iv) An application for a general account under paragraph (c)(1) of this section that complies with the provisions of such paragraph except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification statement will be considered a complete application for a general account under such paragraph, and the certification statement included in such application for a general account will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

(2) * * *

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the acronym ''TR'' will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

* * * * *

■ 116. Section 97.621 is amended by:
■ a. Revising the section heading;
■ b. In paragraphs (c), (d), and (e), removing the word ''period'' and adding in its place the word ''periods'';
■ c. In paragraphs (f) and (g), removing the text ''§ 52.39(e) and (f)'' and adding in its place the text ''§ 52.39(e) or (f)'';
■ d. In paragraph (i), after the text ''through (12)'' removing the comma;
■ e. Revising paragraph (j); and
■ f. Redesignating paragraph (k) as paragraph (l) and adding a new paragraph (k).

The revisions and additions read as follows:

§ 97.621 Recordation of CSAPR SO_2 Group 1 allowance allocations and auction results.

* * * * *

(j) By February 15, 2016 and February 15 of each year thereafter, the Administrator will record in each CSAPR SO_2 Group 1 source's compliance account the CSAPR SO_2 Group 1 allowances allocated to the CSAPR SO_2 Group 1 units at the source in accordance with § 97.612(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR SO_2 Group 1 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.611 or § 97.612 or with a SIP revision approved under § 52.39(e) or (f) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

* * * * *

■ 117. Section 97.622 is amended by revising the section heading to read as follows:

§ 97.622 Submission of CSAPR SO_2 Group 1 allowance transfers.

* * * * *

■ 118. Section 97.623 is amended by:
■ a. Revising the section heading; and
■ b. In paragraph (b), after the word ''allocated'' adding the words ''or auctioned''.

The revision reads as follows:

§ 97.623 Recordation of CSAPR SO_2 Group 1 allowance transfers.

* * * * *

■ 119. Section 97.624 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';
■ c. Revising paragraphs (c)(2)(i) and (ii); and
■ d. In paragraph (d), after the word ''allocated'' adding the words ''or auctioned''.

The revisions read as follows:

§ 97.624 Compliance with CSAPR SO_2 Group 1 emissions limitation.

* * * * *

(c) * * *

(2) * * *

(i) Any CSAPR SO_2 Group 1 allowances that were recorded in the compliance account pursuant to § 97.621 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR SO_2 Group 1 allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

* * * * *

■ 120. Section 97.625 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';
■ c. In paragraph (b)(2)(iii) introductory text, removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(1)(ii)''; and
■ d. In paragraph (b)(2)(iii)(B), after the words ''availability of'' adding the words ''the calculations incorporating''.

The revision reads as follows:

§ 97.625 Compliance with CSAPR SO_2 Group 1 assurance provisions.

* * * * *

§ 97.628 [Amended]

■ 121. Section 97.628, paragraph (b) is amended by removing the text ''paragraph (a)(1)'' and adding in its place the text ''paragraph (a)''.

■ 122. Section 97.630 is amended by:
■ a. Revising paragraph (b) introductory text and paragraphs (b)(1) and (2);
■ b. In paragraph (b)(3) introductory text, removing the text ''§§ 75.4(e)(1) through (e)(4)'' and adding in its place the text ''§ 75.4(e)(1) through (4)''; and
■ c. In paragraph (b)(3)(iii), after the text ''§ 75.66'' adding the words ''of this chapter''.

The revisions read as follows:

§ 97.630 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR SO_2 Group 1 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the later of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the later of the following dates:

(1) January 1, 2015; or

(2) 180 calendar days after the date on which the unit commences commercial operation.

* * * * *

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§ 97.631 [Amended]

■ 123. Section 97.631 is amended by:

■ a. Italicizing the headings of paragraphs (d)(1) through (3), (d)(3)(i) through (iv), (d)(3)(iv)(A) through (D), and (d)(3)(v);

■ b. In paragraph (d)(3) introductory text, removing the text "§§ " and adding in its place the text "§ "; and

■ c. Redesignating paragraphs (d)(3)(v)(A)(1) through (3) as paragraphs (d)(3)(v)(A)(*1*) through (*3*).

■ 124. Section 97.634 is amended by:

■ a. In paragraph (b), after the words "comply with" adding the word "the"; and

■ b. Revising paragraphs (d)(1) and (3).

The revisions read as follows:

§ 97.634 Recordkeeping and reporting.

* * * * *

(d) * * *

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for a CSAPR SO_2 Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with the later of:

(i) The calendar quarter covering January 1, 2015 through March 31, 2015; or

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.630(b).

* * * * *

(3) For CSAPR SO_2 Group 1 units that are also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

* * * * *

§ 97.635 [Amended]

■ 125. Section 97.635 is amended by redesignating paragraphs (b)(i) through (v) as paragraphs (b)(1) through (5).

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 126. The heading of subpart DDDDD of part 97 is revised to read as set forth above.

§ 97.701 [Amended]

■ 127. Section 97.701 is amended by removing the text "Transport Rule (TR) SO_2 Group 2 Trading Program" and adding in its place the text "Cross-State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program".

§§ 97.702 through 97.735 [Amended]

■ 128. Sections 97.702 through 97.735 are amended by removing the text "TR" wherever it appears and adding in its place the text "CSAPR".

■ 129. Section 97.702 is amended by:

■ a. Revising the introductory text and the definitions "Allowable SO_2 emission rate" and "Allowance Management System";

■ b. In the definition "Allowance Management System account", removing the word "holding" and adding in its place the text "auction, holding";

■ c. Revising the definition "Alternate designated representative";

■ d. Adding in alphabetical order the definition "Auction";

■ e. In the definition "Cogeneration system", removing the words "steam turbine";

■ f. In the definition "Commence commercial operation", paragraph (2) introductory text, after the words "defined in" adding the word "the";

■ g. In the definition "Common designated representative's share", paragraph (2), removing the words "and of the total" and adding in their place the words "and the total";

■ h. Placing the newly amended definitions "CSAPR NO_X Annual Trading Program", "CSAPR NO_X Ozone Season Trading Program", "CSAPR SO_2 Group 2 allowance", "CSAPR SO_2 Group 2 allowance deduction or deduct CSAPR SO_2 Group 2 allowances", "CSAPR SO_2 Group 2 allowances held or hold CSAPR SO_2 Group 2 allowances", "CSAPR SO_2 Group 2 emissions limitation", "CSAPR SO_2 Group 2 source", "CSAPR SO_2 Group 2 Trading Program", and "CSAPR SO_2 Group 2 unit" in alphabetical order in the section;

■ i. Removing the newly amended definition "CSAPR NO_X Ozone Season Trading Program";

■ j. Adding in alphabetical order the definitions "CSAPR NO_X Ozone Season Group 1 Trading Program" and "CSAPR NO_X Ozone Season Group 2 Trading Program";

■ k. Italicizing the newly amended definition headings "CSAPR SO_2 Group 2 allowance deduction or deduct CSAPR SO_2 Group 2 allowances" and "CSAPR SO_2 Group 2 allowances held or hold CSAPR SO_2 Group 2 allowances";

■ l. Revising the newly amended definition "CSAPR SO_2 Group 2 Trading Program" and the definition "Designated representative";

■ m. In the definition "Fossil fuel", paragraph (2), removing the text "§§" and adding in its place the text "§ ";

■ n. Removing the definition "Gross electrical output";

■ o. Revising the definitions "Heat input", "Heat input rate", and "Heat rate";

■ p. In the definition heading "Maximum design heat input", after the words "heat input" adding the word "rate";

■ q. Revising the definition "Potential electrical output capacity";

■ r. In the definition "Sequential use of energy", paragraph (2), after the word "from" adding the word "a"; and

■ s. Revising the definition "State".

The revisions and additions read as follows:

§ 97.702 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym "CSAPR" shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym "TR" in place of the acronym "CSAPR":

* * * * *

Allowable SO_2 emission rate means, for a unit, the most stringent State or federal SO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR SO_2 Group 2 allowances under the CSAPR SO_2 Group 2 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

* * * * *

Alternate designated representative means, for a CSAPR SO_2 Group 2 source and each CSAPR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR SO_2 Group 2 Trading Program. If the CSAPR SO_2 Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season

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Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

* * * * *

Auction means, with regard to CSAPR SO_2 Group 2 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under § 52.39(h) or (i) of this chapter, of such CSAPR SO_2 Group 2 allowances to be initially recorded in an Allowance Management System account.

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and § 52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with this subpart and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

Designated representative means, for a CSAPR SO_2 Group 2 source and each CSAPR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR SO_2 Group 2 Trading Program. If the CSAPR SO_2 Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

* * * * *

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

* * * * *

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

* * * * *

State means one of the States that is subject to the CSAPR SO_2 Group 2 Trading Program pursuant to § 52.39(a), (c), (g) through (k), and (m) of this chapter.

* * * * *

§ 97.703 [Amended]

■ 130. Section 97.703 is amended by:

■ a. Adding in alphabetical order the list entry ''CSAPR—Cross-State Air Pollution Rule'';

■ b. Removing the list entry ''kW—kilowatt electrical'';

■ c. Removing the list entry ''kWh—kilowatt hour'' and adding in its place the entry ''kWh—kilowatt-hour'';

■ d. Removing the list entry ''MWh—megawatt hour'' and adding in its place the entry ''MWh—megawatt-hour''; and

■ e. Adding in alphabetical order the list entries ''SIP—State implementation plan'' and ''TR—Transport Rule''.

§ 97.704 [Amended]

■ 131. Section 97.704 is amended by:

■ a. In paragraph (b)(1)(i)(B), removing the word ''electric'' and adding in its place the word ''electrical'';

■ b. In paragraph (b)(2)(ii), removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(2)(i)''; and

■ c. Italicizing the headings of paragraphs (c)(1) and (2).

§ 97.705 [Amended]

■ 132. Section 97.705, paragraph (b) is amended by italicizing the heading.

§ 97.706 [Amended]

■ 133. Section 97.706 is amended by:

■ a. Italicizing the headings of paragraphs (c)(1) and (2) and (c)(4) through (7);

■ b. In paragraph (c)(2)(ii), after the words ''immediately after'' adding the words ''the year of'';

■ c. In paragraph (c)(4) heading, after the words ''Vintage of'' adding the text ''CSAPR SO_2 Group 2'';

■ d. In paragraphs (c)(4)(i) and (ii), after the word ''allocated'' adding the words ''or auctioned''; and

■ e. In paragraph (d)(2), removing the text ''subpart H'' and adding in its place the text ''subpart B''.

■ 134. Section 97.710 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a) introductory text;

■ c. In paragraphs (a)(1) through (7):

■ i. Removing the word ''trading'' wherever it appears and adding in its place the text ''Group 2 trading'';

■ ii. Removing the text ''SO_2 new'' wherever it appears and adding in its place the word ''new''; and

■ iii. Removing the text ''SO_2 Indian'' wherever it appears and adding in its place the word ''Indian'';

■ d. In paragraphs (b)(1) through (7), removing the text ''SO_2''; and

■ e. Revising paragraph (c).

The revisions read as follows:

§ 97.710 State SO_2 Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State SO_2 Group 2 trading budgets, new unit set-asides, and Indian

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country new unit set-asides for allocations of CSAPR SO_2 Group 1 allowances for the control periods in 2015 and thereafter are as follows:

* * * * *

(c) Each State SO_2 Group 2 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

■ 135. Section 97.711 is amended by:
■ a. Revising the section heading;
■ b. Italicizing the headings of paragraphs (b)(1) and (2);
■ c. In paragraph (b)(1)(iii), after the text ''November 30 of'' adding the word ''the'';
■ d. In paragraph (b)(1)(iv)(B), removing the words ''the each'' and adding in their place the word ''each'';
■ e. In paragraph (b)(2)(iii), after the text ''November 30 of'' adding the word ''the'';
■ f. In paragraph (b)(2)(iv)(B), removing the words ''the each'' and adding in their place the word ''each'';
■ g. In paragraph (c)(1) introductory text, removing the word ''approved'' two times and adding in its place the words ''approved under'';
■ h. In paragraph (c)(1)(ii), removing the text ''§ 52.39(g), (h), or (i)'' and adding in its place the text ''§ 52.39(h) or (i)'';
■ i. In paragraph (c)(5)(i)(B), after the text ''§ 52.39(h) or (i)'' adding the words ''of this chapter'';
■ j. In paragraph (c)(5)(ii) introductory text, removing the words ''this paragraph'' and adding in their place the words ''this section'';
■ k. In paragraph (c)(5)(ii)(B), after the text ''§ 52.39(h) or (i)'' adding the words ''of this chapter''; and
■ l. In paragraph (c)(5)(iii), removing the words ''this paragraph'' and adding in their place the words ''this section''.

The revision reads as follows:

§ 97.711 Timing requirements for CSAPR SO_2 Group 2 allowance allocations.

* * * * *

■ 136. Section 97.712 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(2), removing the text ''§§ '' and adding in its place the text ''§ '';
■ c. In paragraph (a)(4)(i), removing the text ''paragraph (a)(1)(i) through (iii)'' and adding in its place the text ''paragraphs (a)(1)(i) through (iii)'';
■ d. In paragraph (a)(4)(ii), after the text ''paragraph (a)(4)(i)'' adding the words ''of this section'';
■ e. In paragraph (a)(9)(i), after the text ''November 30 of'' adding the word ''the'';
■ f. In paragraph (b)(4)(ii), after the text ''paragraph (b)(4)(i)'' adding the words ''of this section'';
■ g. In paragraph (b)(9)(i), after the text ''November 30 of'' adding the word ''the''; and
■ h. In paragraph (b)(10)(ii), removing the text ''§ 52.39(g), (h), or (i)'' and adding in its place the text ''§ 52.39(h) or (i)''.

The revision reads as follows:

§ 97.712 CSAPR SO_2 Group 2 allowance allocations to new units.

* * * * *

■ 137. Section 97.716 is amended by:
■ a. In paragraph (a)(1), removing the word ''Country'' and adding in its place the word ''country''; and
■ b. Adding paragraph (c).

The additions read as follows:

§ 97.716 Certificate of representation.

* * * * *

(c) A certificate of representation under this section that complies with the provisions of paragraph (a) of this section except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

■ 138. Section 97.720 is amended by:
■ a. Italicizing the headings of paragraphs (c)(1) through (6);
■ b. Adding paragraph (c)(1)(iv);
■ c. In paragraph (c)(2)(i) introductory text, removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ d. Adding paragraph (c)(2)(iv);
■ e. In paragraph (c)(4)(i), removing the text ''paragraph (b)(1)'' and adding in its place the text ''paragraph (c)(1)'';
■ f. In paragraph (c)(5)(iii)(D), removing the words ''authorized representative'' and adding in their place the words ''authorized account representative''; and
■ g. In paragraph (c)(5)(v), removing the word ''designated'' two times and adding in its place the words ''authorized account''.

The additions read as follows:

§ 97.720 Establishment of compliance accounts, assurance accounts, and general accounts.

* * * * *

(c) * * *

(1) * * *

(iv) An application for a general account under paragraph (c)(1) of this section that complies with the provisions of such paragraph except that it contains the acronym ''TR'' in place of the acronym ''CSAPR'' in the required certification statement will be considered a complete application for a general account under such paragraph, and the certification statement included in such application for a general account will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

(2) * * *

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the acronym ''TR'' will be interpreted as if the acronym ''CSAPR'' appeared in place of the acronym ''TR''.

* * * * *

■ 139. Section 97.721 is amended by:
■ a. Revising the section heading;
■ b. In paragraphs (c), (d), and (e), removing the word ''period'' and adding in its place the word ''periods''';
■ c. In paragraphs (f) and (g), removing the text ''§ 52.39(h) and (i)'' and adding in its place the text ''§ 52.39(h) or (i)'';
■ d. In paragraph (i), after the text ''through (12)'' removing the comma;
■ e. Revising paragraph (j); and
■ f. Redesignating paragraph (k) as paragraph (l) and adding a new paragraph (k).

The revisions and additions read as follows:

§ 97.721 Recordation of CSAPR SO_2 Group 2 allowance allocations and auction results.

* * * * *

(j) By February 15, 2016 and February 15 of each year thereafter, the Administrator will record in each CSAPR SO_2 Group 2 source's compliance account the CSAPR SO_2 Group 2 allowances allocated to the CSAPR SO_2 Group 2 units at the source in accordance with § 97.712(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR SO_2 Group 2 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.711 or § 97.712 or with a SIP revision approved under § 52.39(h) or (i) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

* * * * *

■ 140. Section 97.722 is amended by revising the section heading to read as follows:

§ 97.722 Submission of CSAPR SO_2 Group 2 allowance transfers.

* * * * *

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■ 141. Section 97.723 is amended by:
■ a. Revising the section heading; and
■ b. In paragraph (b), after the word ''allocated'' adding the words ''or auctioned''.

The revision reads as follows:

§ 97.723 Recordation of CSAPR SO_2 Group 2 allowance transfers.

* * * * *

■ 142. Section 97.724 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';
■ c. Revising paragraphs (c)(2)(i) and (ii) ; and
■ d. In paragraph (d), after the word ''allocated'' adding the words ''or auctioned''.

The revisions read as follows:

§ 97.724 Compliance with CSAPR SO_2 Group 2 emissions limitation.

* * * * *

(c) * * *

(2) * * *

(i) Any CSAPR SO_2 Group 2 allowances that were recorded in the compliance account pursuant to § 97.721 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR SO_2 Group 2 allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

* * * * *

■ 143. Section 97.725 is amended by:
■ a. Revising the section heading;
■ b. In paragraph (a)(1), after the word ''allocated'' adding the words ''or auctioned'';
■ c. In paragraph (b)(2)(iii) introductory text, removing the text ''paragraph (b)(1)(i)'' and adding in its place the text ''paragraph (b)(1)(ii)'';
■ d. In paragraph (b)(2)(iii)(B), after the words ''availability of'' adding the words ''the calculations incorporating''; and
■ e. In paragraph (b)(6)(iii)(B), after the word ''appropriate'' removing the word ''at''.

The revision reads as follows:

§ 97.725 Compliance with CSAPR SO_2 Group 2 assurance provisions.

* * * * *

§ 97.728 [Amended]

■ 144. Section 97.728, paragraph (b) is amended by removing the text ''paragraph (a)(1)'' and adding in its place the text ''paragraph (a)''.

■ 145. Section 97.730 is amended by:
■ a. Italicizing the heading of paragraph (a);
■ b. Revising paragraph (b) introductory text and paragraphs (b)(1) and (2);
■ c. In paragraph (b)(3) introductory text, removing the text ''§§ 75.4(e)(1) through (e)(4)'' and adding in its place the text ''§ 75.4(e)(1) through (4)''; and
■ d. In paragraph (b)(3)(iii), after the text ''§ 75.66'' adding the words ''of this chapter''.

The revisions read as follows:

§ 97.730 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR SO_2 Group 2 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the later of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the later of the following dates:

(1) January 1, 2015; or

(2) 180 calendar days after the date on which the unit commences commercial operation.

* * * * *

§ 97.731 [Amended]

■ 146. Section 97.731 is amended by:
■ a. Italicizing the headings of paragraphs (d)(1) through (3), (d)(3)(i) through (iv), (d)(3)(iv)(A) through (D), and (d)(3)(v);
■ b. In paragraph (d)(3) introductory text, removing the text ''§§ '' and adding in its place the text ''§ ''; and
■ c. Redesignating paragraphs (d)(3)(v)(A)(1) through (3) as paragraphs (d)(3)(v)(A)(*1*) through (*3*).

■ 147. Section 97.734 is amended by:
■ a. In paragraph (b), after the words ''comply with'' adding the word ''the''; and
■ b. Revising paragraphs (d)(1) and (3).

The revisions read as follows:

§ 97.734 Recordkeeping and reporting.

* * * * *

(d) * * *

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for a CSAPR SO_2 Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with the later of:

(i) The calendar quarter covering January 1, 2015 through March 31, 2015; or

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.730(b).

* * * * *

(3) For CSAPR SO_2 Group 2 units that are also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

* * * * *

§ 97.735 [Amended]

■ 148. Section 97.735 is amended by redesignating paragraphs (b)(i) through (v) as paragraphs (b)(1) through (5).

■ 149. Part 97 is amended by adding subpart EEEEE, consisting of §§ 97.801 through 97.835, to read as follows:

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

Sec.

Purpose.
Definitions.
Measurements, abbreviations, and acronyms.
Applicability.
Retired unit exemption. 97.806
Standard requirements. 97.807
Computation of time.
97.808 Administrative appeal procedures.
97.809 [Reserved]
State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.
Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.
CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.
Authorization of designated representative and alternate designated representative.
Responsibilities of designated representative and alternate designated representative.
Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
Certificate of representation. 97.817
Objections concerning designated representative and alternate designated representative.
Delegation by designated representative and alternate designated representative.
[Reserved]
Establishment of compliance accounts, assurance accounts, and general accounts.
Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.
Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.
Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.
Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.

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Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

§ 97.801 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program, under section 110 of the Clean Air Act and § 52.38 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

§ 97.802 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym ''CSAPR'' shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym ''TR'' in place of the acronym ''CSAPR'':

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, § 97.526(c), and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(6), (7), (8), or (9) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 2 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 2 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 2 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 2 allowances, the CSAPR NO_X Ozone Season Group 2 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 2 allowances.

Allowable NO_X emission rate means, for a unit, the most stringent State or federal NO_X emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the unit's heat rate in mmBtu/MWh) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR NO_X Ozone Season Group 2 allowances under the CSAPR NO_X Ozone Season Group 2 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, auction, holding, transfer, or deduction of CSAPR NO_X Ozone Season Group 2 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR NO_X Ozone Season Group 2 allowance transfer must be submitted for recordation in a CSAPR NO_X Ozone Season Group 2 source's compliance account in order to be available for use in complying with the source's CSAPR NO_X Ozone Season Group 2 emissions limitation for such control period in accordance with §§ 97.806 and 97.824.

Alternate designated representative means, for a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program. If the CSAPR NO_X Ozone Season Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.825(b)(3) for certain owners and operators of a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in a given State (and Indian country within the borders of such State), in which are held CSAPR NO_X Ozone Season Group 2 allowances available for use for a control period in a given year in complying with the CSAPR NO_X Ozone Season Group 2 assurance provisions in accordance with §§ 97.806 and 97.825.

Auction means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(6), (8), or (9) of this chapter, of such CSAPR NO_X Ozone Season Group 2 allowances to be initially recorded in an Allowance Management System account.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CSAPR NO_X Ozone Season Group 2 allowances held in the general account and, for a CSAPR NO_X Ozone Season Group 2 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured

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parameters in the measurement units required by this subpart.

Base CSAPR NO_X Ozone Season Group 2 source means a source that includes one or more base CSAPR NO_X Ozone Season Group 2 units.

Base CSAPR NO_X Ozone Season Group 2 unit means a CSAPR NO_X Ozone Season Group 2 unit, provided that any unit that would not be a CSAPR NO_X Ozone Season Group 2 unit under § 97.804(a) and (b) is not a base CSAPR NO_X Ozone Season Group 2 unit notwithstanding the provisions of any SIP revision approved by the Administrator under § 52.38(b)(6), (8), or (9) of this chapter.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means ''coal'' as defined in § 72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.805.

(i) For a unit that is a CSAPR NO_X Ozone Season Group 2 unit under § 97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a CSAPR NO_X Ozone Season Group 2 unit under § 97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.805, for a unit that is not a CSAPR NO_X Ozone Season Group 2 unit under § 97.804 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CSAPR NO_X Ozone Season Group 2 unit under § 97.804.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit,

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which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§ 97.813(a) and 97.815(a) as the designated representative for a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.806(c)(2)(iii), the common designated representative's share of the State NO_X Ozone Season Group 2 trading budget with the variability limit for the State for such control period.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NO_X emissions during such control period from a group of one or more base CSAPR NO_X Ozone Season Group 2 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NO_X Ozone Season Group 2 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to a group of one or more base CSAPR NO_X Ozone Season Group 2 units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such base CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such base CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(6), (8), or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b) for such control period and divided by the greater of such State NO_X Ozone Season Group 2 trading budget or the sum of all amounts of CSAPR NO_X Ozone Season Group 2 allowances for such control period treated for purposes of this definition as having been allocated to or purchased in the State's auction for all such base CSAPR NO_X Ozone Season Group 2 units, provided that—

(i) The allocations of CSAPR NO_X Ozone Season Group 2 allowances for any control period taken into account for purposes of this definition exclude any CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period under § 97.526(c)(1) or (3), or under § 97.526(c)(4) or (5) pursuant to an exception under §97.526(c)(1) or (3);

(ii) In the case of the base CSAPR NO_X Ozone Season Group 2 units at a base CSAPR NO_X Ozone Season Group 2 source in a State with regard to which CSAPR NO_X Ozone Season Group 2 allowances have been allocated under § 97.526(c)(2) for a given control period, the units at each such source will be treated, solely for purposes of this definition, as having been allocated under § 97.526(c)(2), or under § 97.526(c)(4) or (5) pursuant to an exception under § 97.526(c)(2), an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 1 allowances allocated for such control period to such units and the total amount of CSAPR NO_X Ozone Season Group 1 allowances purchased by an owner or operator of such units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance account for such source in accordance with the CSAPR NO_X Ozone Season Group 1 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(4) or (5) of this chapter, divided by the conversion factor determined under § 97.526(c)(2)(ii) with regard to the State's SIP revision under § 52.38(b)(6) of this chapter, and rounded up to the nearest whole allowance; and

(iii) In the case of a base CSAPR NO_X Ozone Season Group 2 unit that operates during, but has no amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under §§ 97.811 and 97.812 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of CSAPR NO_X Ozone Season Group 2 allowances for such control period equal to the unit's allowable NO_X emission rate applicable to such control period, multiplied by a capacity factor of 0.92 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.32 (if the unit is a simple combustion turbine during such control period), 0.71 (if the unit is a combined cycle turbine during such control period), 0.73 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.44 (for any other unit), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a CSAPR NO_X Ozone Season Group 2 source under this subpart, in which any CSAPR NO_X Ozone Season Group 2 allowance allocations to the CSAPR NO_X Ozone Season Group 2 units at the source are recorded and in which are held any CSAPR NO_X Ozone Season Group 2 allowances available for use for a control period in a given year in complying with the source's CSAPR NO_X Ozone Season Group 2 emissions limitation in accordance with §§ 97.806 and 97.824.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture

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content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.830 through 97.835. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting May 1 of a calendar year, except as provided in § 97.806(c)(3), and ending on September 30 of the same year, inclusive.

CSAPR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_X.

CSAPR NO_X Ozone Season Group 1 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart BBBBB of this part, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(3), (4), or (5) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 1 Trading Program.

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i) and (ii), (b)(3) through (5), and (b)(10) through (12) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart or § 97.526(c), or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(6), (7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program.

CSAPR NO_X Ozone Season Group 2 allowance deduction or *deduct CSAPR NO_X Ozone Season Group 2 allowances* means the permanent withdrawal of CSAPR NO_X Ozone Season Group 2 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation) or from an assurance account (*e.g.,* in order to account for compliance with the assurance provisions under §§ 97.806 and 97.825).

CSAPR NO_X Ozone Season Group 2 allowances held or *hold CSAPR NO_X Ozone Season Group 2 allowances* means the CSAPR NO_X Ozone Season Group 2 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, CSAPR NO_X Ozone Season Group 2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CSAPR NO_X Ozone Season Group 2 allowance transfer in accordance with this subpart.

CSAPR NO_X Ozone Season Group 2 emissions limitation means, for a CSAPR NO_X Ozone Season Group 2 source, the tonnage of NO_X emissions authorized in a control period in a given year by the CSAPR NO_X Ozone Season Group 2 allowances available for deduction for the source under § 97.824(a) for such control period.

CSAPR NO_X Ozone Season Group 2 source means a source that includes one or more CSAPR NO_X Ozone Season Group 2 units.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with this subpart and § 52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

CSAPR NO_X Ozone Season Group 2 unit means a unit that is subject to the CSAPR NO_X Ozone Season Group 2 Trading Program.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and § 52.39 (a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by

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the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Designated representative means, for a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program. If the CSAPR NO_X Ozone Season Group 2 source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source during a control period in a given year that exceeds the CSAPR NO_X Ozone Season Group 2 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on ''average annual fuel consumption of fossil fuel'' in § 97.804(b)(2)(i)(B) and (b)(2)(ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the quotient (in mmBtu/unit of load) of the unit's maximum design heat input rate (in Btu/hr) divided by the product of 1,000,000 Btu/mmBtu and the unit's maximum hourly load.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input rate means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means ''natural gas'' as defined in § 72.2 of this chapter.

Newly affected CSAPR NO_X Ozone Season Group 2 unit means a unit that was not a CSAPR NO_X Ozone Season Group 2 unit when it began operating but that thereafter becomes a CSAPR NO_X Ozone Season Group 2 unit.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at a source respectively, any person who operates, controls, or supervises a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit;

(2) Any holder of a leasehold interest in a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly)

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on the revenues or income from such CSAPR NO_X Ozone Season Group 2 unit; and

(3) Any purchaser of power from a CSAPR NO_X Ozone Season Group 2 unit at the source or the CSAPR NO_X Ozone Season Group 2 unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means ''permitting authority'' as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CSAPR NO_X Ozone Season Group 2 allowances, the moving of CSAPR NO_X Ozone Season Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from a useful thermal energy application or process in electricity production.

Serial number means, for a CSAPR NO_X Ozone Season Group 2 allowance, the unique identification number assigned to each CSAPR NO_X Ozone Season Group 2 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the CSAPR NO_X Ozone Season Group 2 Trading Program pursuant to § 52.38(b)(1), (2)(i) and (iii), (6) through (11), and (13) of this chapter.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

LHV = HHV ¥ 10.55 (W + 9H)

where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.803 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
CSAPR—Cross-State Air Pollution Rule
H_2O—water
hr—hour kWh—
kilowatt-hour lb—
pound mmBtu—
million Btu
MWe—megawatt electrical
MWh—megawatt-hour
NO_X—nitrogen oxides O_2—
oxygen
ppm—parts per million scfh—
standard cubic feet per hour SIP—
State implementation plan SO_2—
sulfur dioxide TR—Transport Rule
yr—year

§ 97.804 Applicability.

(a) Except as provided in paragraph (b) of this section:

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(1) The following units in a State (and Indian country within the borders of such State) shall be CSAPR NO_X Ozone Season Group 2 units, and any source that includes one or more such units shall be a CSAPR NO_X Ozone Season Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CSAPR NO_X Ozone Season Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a CSAPR NO_X Ozone Season Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (b)(2)(i) of this section shall not be a CSAPR NO_X Ozone Season Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a CSAPR NO_X Ozone Season Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a CSAPR NO_X Ozone Season Group 2 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a CSAPR NO_X Ozone Season Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(2)(i) of this section, the unit shall become a CSAPR NO_X Ozone Season Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a CSAPR NO_X Ozone Season Group 2 unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, of the CSAPR NO_X Ozone Season Group 2 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: ''I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CSAPR NO_X Ozone Season Group 2 Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.805 Retired unit exemption.

(a)(1) Any CSAPR NO_X Ozone Season Group 2 unit that is permanently retired shall be exempt from § 97.806(b) and (c)(1), § 97.824, and §§ 97.830 through 97.835.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CSAPR NO_X Ozone Season Group 2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall

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comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.806 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.813 through 97.818.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.830 through 97.835.

(2) The emissions data determined in accordance with §§ 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under §§ 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements*—(1) *CSAPR NO_X Ozone Season Group 2 emissions limitation.* (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under § 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under § 97.824(d); and

(B) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *CSAPR NO_X Ozone Season Group 2 assurance provisions.* (i) If total NO_X emissions during a control period in a given year from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under § 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.825(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii) Total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control

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period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* (i) A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under § 97.830(b) and for each control period thereafter.

(ii) A base CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under § 97.830(b) and for each control period thereafter.

(4) *Vintage of CSAPR NO_X Ozone Season Group 2 allowances held for compliance.* (i) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(ii) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) *Allowance Management System requirements.* Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.830 through 97.835 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.816 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in § 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under § 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.807 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CSAPR NO_X Ozone Season Group 2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CSAPR NO_X Ozone Season Group 2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the

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CSAPR NO_X Ozone Season Group 2 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.808 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program are set forth in part 78 of this chapter.

§ 97.809 [Reserved]

§ 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 2 allowances for the control periods in 2017 and thereafter are as follows:

(1) *Alabama.* (i) The NO_X Ozone Season Group 2 trading budget is 13,211 tons.

(ii) The new unit set-aside is 255 tons.

(iii) The Indian country new unit set-aside is 13 tons.

(2) *Arkansas.* (i) The NO_X Ozone Season Group 2 trading budget for 2017 is 12,048 tons and for 2018 and thereafter is 9,210 tons.

(ii) The new unit set-aside for 2017 is 240 tons and for 2018 and thereafter is 185 tons.

(iii) [Reserved]

(3) *Georgia.* (i) The NO_X Ozone Season Group 2 trading budget is 8,481 tons.

(ii) The new unit set-aside is 168 tons.

(iii) [Reserved]

(4) *Illinois.* (i) The NO_X Ozone Season Group 2 trading budget is 14,601 tons.

(ii) The new unit set-aside is 302 tons.

(iii) [Reserved]

(5) *Indiana.* (i) The NO_X Ozone Season Group 2 trading budget is 23,303 tons.

(ii) The new unit set-aside is 468 tons.

(iii) [Reserved]

(6) *Iowa.* (i) The NO_X Ozone Season Group 2 trading budget is 11,272 tons.

(ii) The new unit set-aside is 324 tons.

(iii) The Indian country new unit set-aside is 11 tons.

(7) *Kansas.* (i) The NO_X Ozone Season Group 2 trading budget is 8,027 tons.

(ii) The new unit set-aside is 148 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(8) *Kentucky.* (i) The NO_X Ozone Season Group 2 trading budget is 21,115 tons.

(ii) The new unit set-aside is 426 tons.

(iii) [Reserved]

(9) *Louisiana.* (i) The NO_X Ozone Season Group 2 trading budget is 18,639 tons.

(ii) The new unit set-aside is 352 tons.

(iii) The Indian country new unit set-aside is 19 tons.

(10) *Maryland.* (i) The NO_X Ozone Season Group 2 trading budget is 3,828 tons.

(ii) The new unit set-aside is 152 tons.

(iii) [Reserved]

(11) *Michigan.* (i) The NO_X Ozone Season Group 2 trading budget is 17,023 tons.

(ii) The new unit set-aside is 665 tons.

(iii) The Indian country new unit set-aside is 17 tons.

(12) *Mississippi.* (i) The NO_X Ozone Season Group 2 trading budget is 6,315 tons.

(ii) The new unit set-aside is 120 tons.

(iii) The Indian country new unit set-aside is 6 tons.

(13) *Missouri.* (i) The NO_X Ozone Season Group 2 trading budget is 15,780 tons.

(ii) The new unit set-aside is 324 tons.

(iii) [Reserved]

(14) *New Jersey.* (i) The NO_X Ozone Season Group 2 trading budget is 2,062 tons.

(ii) The new unit set-aside is 192 tons.

(iii) [Reserved]

(15) *New York.* (i) The NO_X Ozone Season Group 2 trading budget is 5,135 tons.

(ii) The new unit set-aside is 252 tons.

(iii) The Indian country new unit set-aside is 5 tons.

(16) *Ohio.* (i) The NO_X Ozone Season Group 2 trading budget is 19,522 tons.

(ii) The new unit set-aside is 401 tons.

(iii) [Reserved]

(17) *Oklahoma.* (i) The NO_X Ozone Season Group 2 trading budget is 11,641 tons.

(ii) The new unit set-aside is 221 tons.

(iii) The Indian country new unit set-aside is 12 tons.

(18) *Pennsylvania.* (i) The NO_X Ozone Season Group 2 trading budget is 17,952 tons.

(ii) The new unit set-aside is 541 tons.

(iii) [Reserved]

(19) *Tennessee.* (i) The NO_X Ozone Season Group 2 trading budget is 7,736 tons.

(ii) The new unit set-aside is 156 tons.

(iii) [Reserved]

(20) *Texas.* (i) The NO_X Ozone Season Group 2 trading budget is 52,301 tons.

(ii) The new unit set-aside is 998 tons.

(iii) The Indian country new unit set-aside is 52 tons.

(21) *Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 9,223 tons.

(ii) The new unit set-aside is 562 tons.

(iii) [Reserved]

(22) *West Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 17,815 tons.

(ii) The new unit set-aside is 356 tons.

(iii) [Reserved]

(23) *Wisconsin.* (i) The NO_X Ozone Season Group 2 trading budget is 7,915 tons.

(ii) The new unit set-aside is 151 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(b) The States' variability limits for the State NO_X Ozone Season Group 2 trading budgets for the control periods in 2017 and thereafter are as follows:

(1) The variability limit for Alabama is 2,774 tons.

(2) The variability limit for Arkansas for 2017 is 2,530 tons and for 2018 and thereafter is 1,934 tons.

(3) The variability limit for Georgia is 1,781 tons.

(4) The variability limit for Illinois is 3,066 tons.

(5) The variability limit for Indiana is 4,894 tons.

(6) The variability limit for Iowa is 2,367 tons.

(7) The variability limit for Kansas is 1,686 tons.

(8) The variability limit for Kentucky is 4,434 tons.

(9) The variability limit for Louisiana is 3,914 tons.

(10) The variability limit for Maryland is 804 tons.

(11) The variability limit for Michigan is 3,575 tons.

(12) The variability limit for Mississippi is 1,326 tons.

(13) The variability limit for Missouri is 3,314 tons.

(14) The variability limit for New Jersey is 433 tons.

(15) The variability limit for New York is 1,078 tons.

(16) The variability limit for Ohio is 4,100 tons.

(17) The variability limit for Oklahoma is 2,445 tons.

(18) The variability limit for Pennsylvania is 3,770 tons.

(19) The variability limit for Tennessee is 1,625 tons.

(20) The variability limit for Texas is 10,983 tons.

(21) The variability limit for Virginia is 1,937 tons.

(22) The variability limit for West Virginia is 3,741 tons.

(23) The variability limit for Wisconsin is 1,662 tons.

(c) Each State NO_X Ozone Season Group 2 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

(a) *Existing units.* (1) CSAPR NO_X Ozone Season Group 2 allowances are

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allocated, for the control periods in 2017 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 2 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2016, during the control period in two consecutive years, such unit will not be allocated the CSAPR NO_X Ozone Season Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All CSAPR NO_X Ozone Season Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the unit in accordance with paragraph (b) of this section.

(b) New units—(1) *New unit set-asides.* (i) By June 1, 2017 and June 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in a State, in accordance with § 97.812(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 2 units) are in accordance with § 97.812(a)(2) through (7) and (12) and §§ 97.806(b)(2) and 97.830 through 97.835.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.812(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any CSAPR NO_X Ozone Season Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_X Ozone Season Group 2 units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_X Ozone Season Group 2 units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of CSAPR NO_X Ozone Season Group 2 units in each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in accordance with § 97.812(a)(9), (10), and (12) and §§ 97.806(b)(2) and 97.830 through 97.835. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any CSAPR NO_X Ozone Season Group 2 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_X Ozone Season Group 2 allowances in accordance with § 97.812(a)(10).

(2) *Indian country new unit set-asides.* (i) By June 1, 2017 and June 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in Indian country within the borders of a State, in accordance with § 97.812(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 2 units) are in accordance with § 97.812(b)(2) through (7) and (12) and §§ 97.806(b)(2) and 97.830 through 97.835.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.812(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any CSAPR NO_X Ozone Season

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Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_X Ozone Season Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_X Ozone Season Group 2 units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_X Ozone Season Group 2 units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of CSAPR NO_X Ozone Season Group 2 units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the CSAPR NO_X Ozone Season Group 2 allowance allocation to each CSAPR NO_X Ozone Season Group 2 unit in accordance with § 97.812(b)(9), (10), and (12) and §§ 97.806(b)(2) and 97.830 through 97.835. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_X Ozone Season Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any CSAPR NO_X Ozone Season Group 2 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_X Ozone Season Group 2 allowances in accordance with § 97.812(b)(10).

(c) *Units incorrectly allocated CSAPR NO_X Ozone Season Group 2 allowances.* (1) For each control period in 2017 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 2 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(6), (7), (8), or (9) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.812(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit under § 97.804 as of May 1, 2017 and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(6), (7), (8), or (9) of this chapter, the recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit as of May 1, 2017 and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 2 units as of May 1, 2017; or

(B) The recipient is not located as of May 1 of the control period in the State from whose NO_X Ozone Season Group 2 trading budget the CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(6), (7), (8), or (9) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit under § 97.804 as of May 1 of such control period and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, the recipient is not actually a CSAPR NO_X Ozone Season Group 2 unit as of May 1 of such control period and is allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 2 units as of May 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances under § 97.821.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 2 allowances under § 97.821 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.824(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 2 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 2 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 2 allowances under § 97.821 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.824(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 2 allowances.

(5)(i) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 2 trading budget the CSAPR NO_X Ozone Season Group 2 allowances were allocated; or

(B) If the State has a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter covering such control period, include such CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may

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be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:

(A) Transfer such CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter covering such control period, include such CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the CSAPR NO_X Ozone Season Group 2 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CSAPR NO_X Ozone Season Group 2 allowances to the Indian country new unit set-aside for such control period.

§ 97.812 CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.

(a) For each control period in 2017 and thereafter and for the CSAPR NO_X Ozone Season Group 2 units in each State, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the CSAPR NO_X Ozone Season Group 2 units as follows:

(1) The CSAPR NO_X Ozone Season Group 2 allowances will be allocated to the following CSAPR NO_X Ozone Season Group 2 units, except as provided in paragraph (a)(10) of this section:

(i) CSAPR NO_X Ozone Season Group 2 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under § 97.811(a)(1);

(ii) CSAPR NO_X Ozone Season Group 2 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under § 97.811(a)(1) is covered by § 97.811(c)(2) or (3);

(iii) CSAPR NO_X Ozone Season Group 2 units that are allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under § 97.811(a)(1), which allocation is terminated for such control period pursuant to § 97.811(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, CSAPR NO_X Ozone Season Group 2 units under § 97.811(c)(1)(ii) whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under § 97.811(b)(1)(ii)(B) is covered by § 97.811(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 2 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.810(a) and will be allocated additional CSAPR NO_X Ozone Season Group 2 allowances (if any) in accordance with § 97.811(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (a)(1) of this section, an allocation of CSAPR NO_X Ozone Season Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2017;

(ii) The first control period after the control period in which the CSAPR NO_X Ozone Season Group 2 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 2 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 2 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 2 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) of this section in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the CSAPR NO_X Ozone Season Group 2 allowances determined for all such CSAPR NO_X Ozone Season Group 2 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_X Ozone Season Group 2 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.811(b)(1)(i) and (ii), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_X Ozone Season Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 2 allowances referenced in the notice of data availability required under

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§ 97.811(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 2 unit that is in the State, is allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under § 97.811(a)(1), and continues to be allocated CSAPR NO_X Ozone Season Group 2 allowances for such control period in accordance with § 97.811(a)(2), an amount of CSAPR NO_X Ozone Season Group 2 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 2 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.811(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 2 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.811(b)(1)(iii), (iv), and (v), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (a)(9)(iv) of this section, or paragraphs (a)(6), (a)(9)(iii), and (a)(10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, by one CSAPR NO_X Ozone Season Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (a)(9)(iii), and (a)(10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (a)(10) of this section by one CSAPR NO_X Ozone Season Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2017 and thereafter and for the CSAPR NO_X Ozone Season Group 2 units located in Indian country within the borders of each State, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the CSAPR NO_X Ozone Season Group 2 units as follows:

(1) The CSAPR NO_X Ozone Season Group 2 allowances will be allocated to the following CSAPR NO_X Ozone Season Group 2 units, except as provided in paragraph (b)(10) of this section:

(i) CSAPR NO_X Ozone Season Group 2 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances in the notice of data availability issued under § 97.811(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, CSAPR NO_X Ozone Season Group 2 units under § 97.811(c)(1)(ii) whose allocation of an amount of CSAPR NO_X Ozone Season Group 2 allowances for such control period in the notice of data availability issued under § 97.811(b)(2)(ii)(B) is covered by § 97.811(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 2 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.810(a) and will be allocated additional CSAPR NO_X Ozone Season Group 2 allowances (if any) in accordance with § 97.811(c)(5).

(3) The Administrator will determine, for each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (b)(1) of this section, an allocation of CSAPR NO_X Ozone Season Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2017; and

(ii) The first control period after the control period in which the CSAPR NO_X Ozone Season Group 2 unit commences commercial operation.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 2 unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this

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section will be an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) of this section in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the CSAPR NO_X Ozone Season Group 2 allowances determined for all such CSAPR NO_X Ozone Season Group 2 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_X Ozone Season Group 2 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.811(b)(2)(i) and (ii), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_X Ozone Season Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_X Ozone Season Group 2 allowances referenced in the notice of data availability required under § 97.811(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_X Ozone Season Group 2 allowances determined for each such CSAPR NO_X Ozone Season Group 2 unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_X Ozone Season Group 2 unit the amount of the CSAPR NO_X Ozone Season Group 2 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_X Ozone Season Group 2 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated CSAPR NO_X Ozone Season Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated CSAPR NO_X Ozone Season Group 2 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter covering such control period, include such unallocated CSAPR NO_X Ozone Season Group 2 allowances in the portion of the State NO_X Ozone Season Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.811(b)(2)(iii), (iv), and (v), of the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each CSAPR NO_X Ozone Season Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (b)(9)(iv) of this section, or paragraphs (b)(6), (b)(9)(iii), and (b)(10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will reduce each unit's allocation under paragraph (b)(7), (b)(9)(iv), or (b)(10) of this section, as applicable, by one CSAPR NO_X Ozone Season Group 2 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (b)(9)(iii), and (b)(10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 2 units in descending order based on the amount of such units' allocations under

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paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one CSAPR NO_X Ozone Season Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.813 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.815, each CSAPR NO_X Ozone Season Group 2 source, including all CSAPR NO_X Ozone Season Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_X Ozone Season Group 2 units at the source and shall act in accordance with the certification statement in § 97.816(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.816:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source in all matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.815, each CSAPR NO_X Ozone Season Group 2 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_X Ozone Season Group 2 units at the source and shall act in accordance with the certification statement in § 97.816(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.816,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.802, and §§ 97.814 through 97.818, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.814 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.818 concerning delegation of authority to make submissions, each submission under the CSAPR NO_X Ozone Season Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each CSAPR NO_X Ozone Season Group 2 source and CSAPR NO_X Ozone Season Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.818.

§ 97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.816. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and the CSAPR NO_X Ozone Season Group 2 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.816. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and the CSAPR NO_X Ozone Season Group 2 units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.816, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of

the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a CSAPR NO_X Ozone Season Group 2 source or a CSAPR NO_X Ozone Season Group 2 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.816 amending the list of owners and operators to reflect the change.

(d) *Changes in units at the source.* Within 30 days of any change in which units are located at a CSAPR NO_X Ozone Season Group 2 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.816 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.816 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CSAPR NO_X Ozone Season Group 2 source, and each CSAPR NO_X Ozone Season Group 2 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the CSAPR NO_X Ozone Season Group 2 source and of each CSAPR NO_X Ozone Season Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 2 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_X Ozone Season Group 2 unit, or where a utility or industrial customer purchases power from a CSAPR NO_X Ozone Season Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_X Ozone Season Group 2 unit at the source; and CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_X Ozone Season Group 2 allowances by contract, CSAPR NO_X Ozone Season Group 2 allowances and proceeds of transactions involving CSAPR NO_X Ozone Season Group 2 allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(c) A certificate of representation under this section or § 97.516 that complies with the provisions of paragraph (a) of this section except that it contains the phrase ''TR NO_X Ozone Season'' in place of the phrase ''CSAPR NO_X Ozone Season Group 2'' in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season''.

§ 97.817 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.816 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.816 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program.

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(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CSAPR NO_X Ozone Season Group 2 allowance transfers.

§ 97.818 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.818(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.818(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under 40 CFR 97.818 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(f) A notice of delegation submitted under paragraph (c) of this section or § 97.518(c) that complies with the provisions of paragraph (c) of this section except that it contains the terms "40 CFR 97.518(d)" and "40 CFR 97.518" in place of the terms "40 CFR 97.818(d)" and "40 CFR 97.818", respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms "40 CFR 97.818(d)" and "40 CFR 97.818" appeared in place of the terms "40 CFR 97.518(d)" and "40 CFR 97.518", respectively.

§ 97.819 [Reserved]

§ 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.816, the Administrator will establish a compliance account for the CSAPR NO_X Ozone Season Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Assurance accounts.* The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.825(b)(3).

(c) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring CSAPR NO_X Ozone Season Group 2 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account

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representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_X Ozone Season Group 2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.''

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(iv) An application for a general account under paragraph (c)(1) of this section or § 97.520(c)(1) that complies with the provisions of paragraph (c)(1) of this section except that it contains the phrase ''TR NO_X Ozone Season'' in place of the phrase ''CSAPR NO_X Ozone Season Group 2'' in the required certification statement will be considered a complete application for a general account under paragraph (c)(1) of this section, and the certification statement included in such application for a general account will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season''.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account in all matters pertaining to the CSAPR NO_X Ozone Season Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the phrase ''TR NO_X Ozone Season'' will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season''.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CSAPR NO_X Ozone Season Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Ozone Season Group 2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall

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submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CSAPR NO_X Ozone Season Group 2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.820(c)(5)(iv) shall be deemed to be an electronic submission by me.''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.820(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under 40 CFR 97.820(c)(5) is terminated.''.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(vi) A notice of delegation submitted under paragraph (c)(5)(iii) of this section or § 97.520(c)(5)(iii) that complies with the provisions of paragraph (c)(5)(iii) of this section except that it contains the terms ''40 CFR 97.520(c)(5)(iv)'' and ''40 CFR 97.520(c)(5)'' in place of the terms ''40 CFR 97.820(c)(5)(iv)'' and ''40 CFR 97.820(c)(5)'', respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c)(5)(iii) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms ''40 CFR 97.820(c)(5)(iv)'' and ''40 CFR 97.820(c)(5)'' appeared in place of the terms ''40 CFR 97.520(c)(5)(iv)'' and ''40 CFR 97.520(c)(5)'', respectively.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted CSAPR NO_X Ozone Season Group 2 allowance transfer under § 97.822 for any CSAPR NO_X Ozone Season Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no CSAPR NO_X Ozone Season Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CSAPR NO_X Ozone Season Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CSAPR NO_X Ozone Season Group 2 allowance transfer under § 97.822 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account

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established under paragraph (a), (b), or (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CSAPR NO_X Ozone Season Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.814(a) and 97.818 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.

(a) By January 9, 2017, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.811(a) for the control period in 2017.

(b) By January 9, 2017, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.811(a) for the control period in 2018, unless the State in which the source is located notifies the Administrator in writing by December 27, 2016 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2017 meeting the requirements of § 52.38(b)(7)(i) through (iv) of this chapter.

(1) If, by April 1, 2017 the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.811(a) for the control period in 2018.

(2) If the State submits to the Administrator by April 1, 2017 and the Administrator approves by October 1, 2017 such complete SIP revision, the Administrator will record by October 1, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source as provided in such approved, complete SIP revision for the control period in 2018.

(3) If the State submits to the Administrator by April 1, 2017 and the Administrator does not approve by October 1, 2017 such complete SIP revision, the Administrator will record by October 1, 2017 in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.811(a) for the control period in 2018.

(c) By July 1, 2018, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with § 97.811(a), or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2019 and 2020.

(d) By July 1, 2019, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with § 97.811(a), or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2021 and 2022.

(e) By July 1, 2020, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with § 97.811(a), or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, for the control periods in 2023 and 2024.

(f) By July 1, 2021 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with § 97.811(a), or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2017 and August 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 2 allowances auctioned to CSAPR NO_X Ozone Season Group 2 units, in accordance with § 97.812(a)(2) through (8) and (12), or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2017 and August 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.812(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.812(a)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By February 15, 2018 and February 15 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.812(b)(9) through (12) for the control period in the year before the year of the applicable

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recordation deadline under this paragraph.

(k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR NO_X Ozone Season Group 2 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.811 or § 97.812 or with a SIP revision approved under § 52.38(b)(6), (8), or (9) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(l) When recording the allocation or auction of CSAPR NO_X Ozone Season Group 2 allowances to a CSAPR NO_X Ozone Season Group 2 unit or other entity in an Allowance Management System account, the Administrator will assign each CSAPR NO_X Ozone Season Group 2 allowance a unique identification number that will include digits identifying the year of the control period for which the CSAPR NO_X Ozone Season Group 2 allowance is allocated or auctioned.

§ 97.822 Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a CSAPR NO_X Ozone Season Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A CSAPR NO_X Ozone Season Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each CSAPR NO_X Ozone Season Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each CSAPR NO_X Ozone Season Group 2 allowance identified by serial number in the transfer.

§ 97.823 Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CSAPR NO_X Ozone Season Group 2 allowance transfer that is correctly submitted under § 97.822, the Administrator will record a CSAPR NO_X Ozone Season Group 2 allowance transfer by moving each CSAPR NO_X Ozone Season Group 2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CSAPR NO_X Ozone Season Group 2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CSAPR NO_X Ozone Season Group 2 allowances allocated or auctioned for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 97.824 for the control period immediately before such allowance transfer deadline.

(c) Where a CSAPR NO_X Ozone Season Group 2 allowance transfer is not correctly submitted under § 97.822, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a CSAPR NO_X Ozone Season Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CSAPR NO_X Ozone Season Group 2 allowance transfer that is not correctly submitted under § 97.822, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.

(a) *Availability for deduction for compliance.* CSAPR NO_X Ozone Season Group 2 allowances are available to be deducted for compliance with a source's CSAPR NO_X Ozone Season Group 2 emissions limitation for a control period in a given year only if the CSAPR NO_X Ozone Season Group 2 allowances:

(1) Were allocated or auctioned for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.823, of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the CSAPR NO_X Ozone Season Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of CSAPR NO_X Ozone Season Group 2 allowances deducted equals the number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at the source for such control period; or

(2) If there are insufficient CSAPR NO_X Ozone Season Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CSAPR NO_X Ozone Season Group 2 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific CSAPR NO_X Ozone Season Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the CSAPR NO_X Ozone Season Group 2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CSAPR NO_X Ozone Season Group 2 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of CSAPR NO_X Ozone Season Group 2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any CSAPR NO_X Ozone Season Group 2 allowances that were recorded in the compliance account pursuant to § 97.821 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other CSAPR NO_X Ozone Season Group 2 allowances that were transferred to and recorded in the compliance account pursuant to this subpart or that were recorded in the

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compliance account pursuant to § 97.526(c), in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the CSAPR NO_X Ozone Season Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CSAPR NO_X Ozone Season Group 2 allowances, allocated or auctioned for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.

(a) *Availability for deduction.* CSAPR NO_X Ozone Season Group 2 allowances are available to be deducted for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions for a control period in a given year by the owners and operators of a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in a State (and Indian country within the borders of such State) only if the CSAPR NO_X Ozone Season Group 2 allowances:

(1) Were allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of base CSAPR NO_X Ozone Season Group 2 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) *Deductions for compliance.* The Administrator will deduct CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2018 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO_X emissions exceed the State assurance level as described in § 97.806(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions from each base CSAPR NO_X Ozone Season Group 2 source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having base CSAPR NO_X Ozone Season Group 2 units with total NO_X emissions exceeding the State assurance level for a control period in a given year, as described in § 97.806(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each base CSAPR NO_X Ozone Season Group 2 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each base CSAPR NO_X Ozone Season Group 2 unit (if any) at the source that operates during, but is not allocated an amount of CSAPR NO_X Ozone Season Group 2 allowances for, such control period, the unit's allowable NO_X emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit's heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more base CSAPR NO_X Ozone Season Group 2 sources and units in the State (and Indian country within the borders of such State), the common designated representative's share of the total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State), the common designated representative's assurance level, and the amount (if any) of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in § 97.806(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with § 97.806(c)(2)(iii), §§ 97.806(b) and 97.830 through 97.835, the definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share'' in § 97.802, and the calculation formula in § 97.806(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having base CSAPR NO_X Ozone Season Group 2 units with total NO_X emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of base CSAPR NO_X Ozone Season Group 2 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold CSAPR NO_X Ozone Season Group 2 allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in

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paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of CSAPR NO_X Ozone Season Group 2 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with § 97.823, of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of CSAPR NO_X Ozone Season Group 2 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold in accordance with § 97.806(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of CSAPR NO_X Ozone Season Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.806(c)(2)(i) for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a base CSAPR NO_X Ozone Season Group 2 source and base CSAPR NO_X Ozone Season Group 2 unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of CSAPR NO_X Ozone Season Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.806(c)(2)(i) for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold for such control period with regard to the base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of CSAPR NO_X Ozone Season Group 2 allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of CSAPR NO_X Ozone Season Group 2 allowances in the assurance account established by the Administrator for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of CSAPR NO_X Ozone Season Group 2 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which CSAPR NO_X Ozone Season Group 2 allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate base CSAPR NO_X Ozone Season Group 2 sources, base CSAPR NO_X Ozone Season Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the CSAPR NO_X Ozone Season Group 2 allowances held in such assurance account equal to the amount of the decrease. If CSAPR NO_X Ozone Season Group 2 allowances were transferred to such assurance account from more than one account, the amount of CSAPR NO_X Ozone Season Group 2 allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of CSAPR NO_X Ozone Season Group 2 allowances transferred to such assurance account for such control period from such transferor account.

(C) Each CSAPR NO_X Ozone Season Group 2 allowance held under

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paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the CSAPR NO_X Ozone Season Group 2 assurance provisions for such control period must be a CSAPR NO_X Ozone Season Group 2 allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

§ 97.826 Banking.

(a) A CSAPR NO_X Ozone Season Group 2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CSAPR NO_X Ozone Season Group 2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 2 allowance is deducted or transferred under § 97.811(c), § 97.823, § 97.824, § 97.825, § 97.827, or § 97.828.

§ 97.827 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.828 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the CSAPR NO_X Ozone Season Group 2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct CSAPR NO_X Ozone Season Group 2 allowances from or transfer CSAPR NO_X Ozone Season Group 2 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

§ 97.829 [Reserved]

§ 97.830 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a CSAPR NO_X Ozone Season Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.802 and in § 72.2 of this chapter shall apply, the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CSAPR NO_X Ozone Season Group 2 unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively as defined in § 97.802, and the term ''newly affected unit'' shall be deemed to mean ''newly affected CSAPR NO_X Ozone Season Group 2 unit''. The owner or operator of a unit that is not a CSAPR NO_X Ozone Season Group 2 unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CSAPR NO_X Ozone Season Group 2 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CSAPR NO_X Ozone Season Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.831 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the latest of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the latest of the following dates:

(1) May 1, 2017;

(2) 180 calendar days after the date on which the unit commences commercial operation; or

(3) Where data for the unit are reported on a control period basis under § 97.834(d)(1)(ii)(B), and where the compliance date under paragraph (b)(2) of this section is not in a month from May through September, May 1 immediately after the compliance date under paragraph (b)(2) of this section.

(4) The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), or (3) of this section shall meet the requirements of § 75.4(e)(1) through (4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under § 97.830 through § 97.835, rather than the monitoring systems required under part 75 of this chapter;

(ii) NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas volumetric flow rate, and O_2 or CO_2 concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.835, rather than § 75.66 of this chapter.

(c) *Reporting data.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.835.

(2) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, NO_X to the atmosphere without accounting for all such NO_X in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission

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monitoring method, and thereby avoid monitoring and recording NO_X mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.805 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.831(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.831 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.830(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.830(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.835 to determine whether the approval applies under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.830(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.830(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.830(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.830(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.830(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.830(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in § 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words ''certification'' and ''initial certification'' are replaced by the word ''recertification'' and the word ''certified'' is replaced by with the word ''recertified''.

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.833.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CSAPR NO_X Ozone Season Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of

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provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CSAPR NO_X Ozone Season Group 2 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.832(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.832 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.831 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification

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procedures in § 97.831 for each disapproved monitoring system.

§ 97.833 Notifications concerning monitoring.

The designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.834 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.814(a).

(b) *Monitoring plans.* The owner or operator of a CSAPR NO_X Ozone Season Group 2 unit shall comply with the requirements of § 75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.831, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1)(i) If a CSAPR NO_X Ozone Season Group 2 unit is subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program or if the owner or operator of such unit chooses to report on an annual basis under this subpart, then the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year.

(ii) If a CSAPR NO_X Ozone Season Group 2 unit is not subject to the Acid Rain Program or the CSAPR NO_X Annual Trading Program, then the designated representative shall either:

(A) Meet the requirements of subpart H of part 75 of this chapter for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit for the entire year in accordance with paragraph (d)(1)(i) of this section; or

(B) Meet the requirements of subpart H of part 75 of this chapter (including the requirements in § 75.74(c) of this chapter) for such unit for the control period and report the NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year.

(2) The designated representative shall report the NO_X mass emissions data and heat input data for a CSAPR NO_X Ozone Season Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter indicated under paragraph (d)(1) of this section beginning by the latest of:

(i) The calendar quarter covering May 1, 2017 through June 30, 2017;

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.830(b); or

(iii) For a unit that reports on a control period basis under paragraph (d)(1)(ii)(B) of this section, if the calendar quarter under paragraph (d)(2)(ii) of this section does not include a month from May through September, the calendar quarter covering May 1 through June 30 immediately after the calendar quarter under paragraph (d)(2)(ii) of this section.

(3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(4) For CSAPR NO_X Ozone Season Group 2 units that are also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(5) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(3) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(1)(ii)(B) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a CSAPR NO_X Ozone Season Group 2 unit may submit a petition under § 75.66 of

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this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.830 through 97.834.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(1) Identification of each unit and source covered by the petition;

(2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(3) A description and diagram of any equipment and procedures used in the proposed alternative;

(4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(5) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

Appendices A through D to Part 97 [Redesignated]

■ 150. Appendices A, B, C, and D to part 97 are redesignated as appendices A, B, C, and D to subpart E of part 97.

[FR Doc. 2016–22240 Filed 10–25–16; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 75, and 96

[FRL–6171–2]

RIN 2060–AH10

Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In accordance with the Clean Air Act (CAA), today's action is a final rule to require 22 States and the District of Columbia to submit State implementation plan (SIP) revisions to prohibit specified amounts of emissions of oxides of nitrogen (NO_x)—one of the precursors to ozone (smog) pollution— for the purpose of reducing NO_x and ozone transport across State boundaries in the eastern half of the United States.

Ground-level ozone has long been recognized, in both clinical and epidemiological research, to affect public health. There is a wide range of ozone-induced health effects, including decreased lung function (primarily in children active outdoors), increased respiratory symptoms (particularly in highly sensitive individuals), increased hospital admissions and emergency room visits for respiratory causes (among children and adults with pre-existing respiratory disease such as asthma), increased inflammation of the lung, and possible long-term damage to the lungs.

In today's action, EPA finds that sources and emitting activities in each of the 22 States and the District of Columbia (23 jurisdictions) emit NO_x in amounts that significantly contribute to nonattainment of the 1-hour and 8-hour ozone national ambient air quality standards (NAAQS), or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States. Further, by today's action, EPA is requiring each of the affected upwind jurisdictions (sometimes referred to as upwind States) to submit SIP revisions prohibiting those amounts of NO_x emissions which significantly contribute to downwind air quality problems. The reduction of those NO_x emissions will bring NO_x emissions in each of those States to within the resulting statewide NO_x emissions budget levels established in today's rule. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. These States will be able to choose any mix of pollution-reduction measures that will achieve the required reductions.

EFFECTIVE DATES: This rule is effective December 28, 1998. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 28, 1998.

ADDRESSES: Dockets containing information relating to this rulemaking (Docket No. A–96–56 and Docket No. A–9–35) are available for public inspection at the Air and Radiation Docket and Information Center (6102), US Environmental Protection Agency, 401 M Street SW, room M–1500, Washington, DC 20460, telephone (202) 260–7548, between 8:00 a.m. and 4:00 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Kimber S. Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–3354; e-mail: scavo.kimber@epa.gov. Please refer to **SUPPLEMENTARY INFORMATION** below for a list of contacts for specific subjects described in today's action.

SUPPLEMENTARY INFORMATION:

Availability of Related Information

Documents related to the Ozone Transport Assessment Group (OTAG) are available on the Agency's Office of Air Quality Planning and Standards' (OAQPS) Technology Transfer Network (TTN) via the web at http://www.epa.gov/ttn/. If assistance is needed in accessing the system, call the help desk at (919) 541–5384 in Research Triangle Park, NC. Documents related to OTAG can be downloaded directly from OTAG's webpage at http://www.epa.gov/ttn/otag/. The OTAG's technical data are located at http://www.iceis.mcnc.org/OTAGDC. The notice of proposed rulemaking for this final action, the supplemental notice of proposed rulemaking, and associated documents are located at http://epa.gov/ttn/oarpg/otagsip.html. Information related to Sections II, Weight of Evidence Determination of Covered States, and IV, Air Quality Assessment, can be obtained in electronic form from the following EPA website: http://www.epa.gov/scram001/regmodcenter/t28.htm. Information related to Section III, Determination of Budgets, may be found on the following EPA website: http://www.epa.gov/capi. All information in electronic form may also be found on diskettes that have been placed in the docket to this rulemaking.

For Additional Information

For technical questions related to the air quality analyses, please contact Norm Possiel; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD–14, Research Triangle Park, NC 27711, telephone (919) 541–5692. For legal questions, please contact Howard J. Hoffman, Office of General Counsel, 401 M Street SW, MC–2344, Washington, DC 20460, telephone (202) 260–5892. For questions concerning the statewide emissions budget revisions, please contact Laurel Schultz; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD–14, Research Triangle Park, NC 27711, telephone (919) 541–5511. For questions concerning SIP reporting requirements, please contact Bill Johnson, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5245. For questions concerning the model cap-and-trade rule, please contact Rob Lacount, Office of Atmospheric Programs, Acid Rain Division, MC–6204J, 401 M Street SW, Washington, DC 20460, telephone (202) 564–9122. For questions concerning the regulatory cost analysis of electricity generating sources, please contact Ravi Srivastava, Office of Atmospheric Programs, Acid Rain Division, MC–6204J, 401 M Street SW, Washington DC 20460, telephone (202) 564–9093. For questions concerning the regulatory cost analysis of other stationary sources and questions concerning the Regulatory Impact Analysis (RIA), please contact Scott Mathias, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD– 15, Research Triangle Park, NC 27711, telephone (919) 541–5310.

Outline

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CFR Revisions and Additions

I. Background

A. Summary of Rulemaking and Affected States

By notice of proposed rulemaking (NPR, proposal, or ''proposed SIP call'') (62 FR 60318, November 7, 1997) and by supplemental notice (SNPR or supplemental proposal) (63 FR 25902, May 11, 1998), EPA proposed to find that NO_X emissions from sources and emitting activities (sources) in 23 jurisdictions (hereinafter also referred to as States) will significantly contribute to nonattainment of the 1-hour and 8-hour ozone NAAQS, or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States throughout the Eastern United States. The EPA based these proposals on data generated by OTAG, public comments, and other relevant information. Today's final action confirms that proposed finding. It also requires, under CAA section 110(a)(1) and 110(k)(5), that the 23 jurisdictions adopt and submit SIP revisions that, in order to assure that their SIPs meet the requirements of section 110(a)(2)(D)(i)(I), contain provisions adequate to prohibit sources in those States from emitting NO_X in amounts that ''contribute significantly to nonattainment in, or interfere with maintenance by,'' a downwind State. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Each of these States and the District of Columbia is required to adopt and submit by September 30, 1999, a SIP revision. The SIP revision must contain measures that will assure that sources in the State reduce their NO_X emissions sufficiently to eliminate the amounts of NO_X emissions that contribute significantly to nonattainment, or that interfere with maintenance, downwind. By eliminating these amounts of NO_X emissions, the control measures will assure that the remaining NO_X emissions will meet the level identified in today's rule as the State's NO_X emissions budget. For simplicity, this final rule may refer to the amounts that such SIP provisions must prohibit in order to meet the statute as the ''significant amounts'' of NO_X emissions. After prohibiting these significant amounts of NO_X, the remaining amounts emitted by sources in the covered States will not ''significantly contribute to nonattainment, or interfere with maintenance by,'' a downwind State, under section 110(a)(2)(D)(i)(I). Section II.C, Weight-of-Evidence Determination of Covered States, describes how EPA determined which States include sources that emit NO_X in amounts of concern (the ''covered'' States), and Sections II.D, Cost Effectiveness of Emissions Reductions; II.E, Comparison of Upwind and Downwind Costs; and III, Determination of Budgets, describe how EPA determined the significant amounts of emissions and the resulting statewide emissions budgets for the States identified above. Section IV, Air Quality Assessment, discusses air quality analyses conducted by EPA which help confirm the decisions and requirements set forth in this rulemaking. Section V, NO_X Control Implementation and Budget Achievement Dates, primarily discusses the dates by which (1) the States must submit SIP revisions in response to today's action, (2) the sources must implement the measures the States choose for the purpose of prohibiting the significant amounts of NO_X, and (3) the States are projected to achieve the budget levels. Section VI, SIP Criteria and Emissions Reporting Requirements, describes the SIP requirements themselves.

The SIP requirements permit each State to determine what measures to adopt to prohibit the significant amounts and hence meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve

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NO_X emissions decreases primarily from large stationary sources in a trading program, EPA encourages States to consider electric utility and large boiler controls under a cap-and-trade program as a cost-effective strategy. The recommended cap-and-trade program is described in more detail in Section VII, NO_X Budget Trading Program. The EPA also recognizes that promotion of energy efficiency can contribute to a cost-effective strategy. In Section VIII, Interaction with Title IV NO_X rule, EPA explains that it is not adopting proposed revisions to the title IV NO_X rule concerning the relationship between this rulemaking and the title IV NO_X rule. The remaining parts of today's action include Section IX, Non-Ozone Benefits of NO_X Reductions, and Section X, Administrative Requirements.

The EPA also conducted a RIA which is available in the docket to this rulemaking as a technical support document (TSD), entitled ''Regulatory Impact Analysis for the Regional NO_X SIP Call'' (docket no. VI–B–09). A detailed explanation of how EPA calculated the budgets is also available as a TSD entitled ''Development of Modeling Inventory and Budgets for the Regional NO_X SIP Call'' (docket no. VI–B–10). These two TSDs have been revised for the final rulemaking. A detailed explanation of the air quality modeling analyses is also available, entitled ''Air Quality Modeling Technical Support Document for the Regional NO_X SIP Call'' (docket no. VI–B–11) for this final rulemaking. This preamble for today's notice responds to some of the comments, but another document, entitled ''Response to Significant Comments on the Finding of Significant Contribution and Rulemaking for Certain States in the OTAG Region for Purposes of Reducing Regional Transport of Ozone,'' is included in the docket (docket no. VI–C–01).

B. General Factual Background

In today's action, EPA takes a significant step toward reducing ozone in the eastern half of the country. Ground-level ozone, the main harmful ingredient in smog, is produced in complex chemical reactions when its precursors, volatile organic compounds (VOC) and NO_X, react in the presence of sunlight. The chemical reactions that create ozone take place while the pollutants are being blown through the air by the wind, which means that ozone can be more severe many miles away from the source of emissions than it is at the source.

The science of ozone formation, transport, and accumulation is complex. Ozone is produced and destroyed in a cyclical set of chemical reactions involving NO_X, VOC and sunlight. Emissions of NO_X and VOC are necessary for the formation of ozone in the lower atmosphere. In part of the cycle of reactions, ozone concentrations in an area can be lowered by the reaction of nitric oxide with ozone, forming nitrogen dioxide; as the air moves downwind and the cycle continues, the nitrogen dioxide forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of NO_X, VOC and ozone, all of which change with time and location.

At ground level, ozone can cause a variety of ill effects to human health, crops and trees. Specifically, ground-level ozone has been shown in clinical and/or epidemiologial studies to have the following health effects:

fl Decreased lung function, primarily in children active outdoors
fl Increased respiratory symptoms, particularly in highly sensitive individuals
fl Hospital admissions and emergency room visits for respiratory causes among children and adults with pre-existing respiratory disease such as asthma
fl Inflammation of the lung
fl Possible long-term damage to the lungs or even premature death.

The new 8-hour primary ambient air quality standard (62 FR 38856, July 18, 1997) will provide increased protection to the public from these health effects.

Each year, ground-level ozone above background is also responsible for significant agricultural crop yield losses. Ozone also causes noticeable foliar damage in many crops, trees, and ornamental plants (i.e., grass, flowers, shrubs, and trees) and causes reduced growth in plants. Studies indicate that current ambient levels of ozone are responsible for damage to forests and ecosystems (including habitat for native animal species).

As part of the efforts to reduce harmful levels of smog, EPA, today, is establishing a requirement for certain States to revise their SIPs in order to implement the necessary regional-scale reductions in NO_X emissions, and, thereby, reduce transported NO_X and ozone. Since air pollution travels across county and State lines, it is essential for State governments and air pollution control agencies to cooperate to solve the problem.

Currently, the following areas, impacted by the 23 jurisdictions that are the subject of today's rulemaking, are designated nonattainment areas for ozone under the 1-hour NAAQS:

Atlanta, GA
Baltimore, MD
Birmingham, AL
Boston-Lawrence-Worcester (eastern MA), MA–NH
Chicago-Gary-Lake County, IL–IN
Cincinnati-Hamilton, OH–KY Door County, WI
Greater Connecticut
Kent & Queen Anne's Counties, MD
Lancaster, PA
Louisville, KY–IN
Manitowoc County, WI
Milwaukee-Racine, WI
Muskegon, MI
New York-Northern New Jersey-Long Island, NY–NJ–CT
Philadelphia-Wilmington-Trenton, PA–NJ– DE–MD
Pittsburgh-Beaver Valley, PA
Portland, ME
Portsmouth-Dover-Rochester, NH
Providence (All RI), RI
St. Louis, MO–IL
Springfield (western MA), MA
Washington, DC–MD–VA

These areas include many of the major urban centers in the eastern half of the Nation. The combined population for these areas is approximately 61.5 million. As described elsewhere, the reductions called for in today's action will reduce ozone levels throughout these areas.

Many more areas currently violate the 8-hour NAAQS. The EPA estimates that a total population of approximately 73 million in the 23 jurisdictions live in counties for which air quality is monitored to be in violation of that NAAQS. The reductions called for in today's action will reduce ozone levels throughout these areas as well.

Moreover, as discussed below, many of these areas are expected to be classified as ''transitional,'' which means, in most cases, that they are expected to come into attainment solely as a result of the reductions required by today's action. Thus, for those who live in these areas, the reductions required under today's action, in-and-of-themselves, are expected to mean the difference between unhealthful ozone levels and acceptable ozone levels.

Please note that EPA will not designate ozone nonattainment areas for the 8-hour NAAQS until 2000, and these designations will be based on the data that are most recently available at that time.

C. Statutory and Regulatory Background

1. CAA Provisions

a. 1970 and 1977 CAA Amendments. For almost 30 years, Congress has focused major efforts on curbing ground-level ozone. In 1970, Congress amended the CAA to require, in title I, that EPA issue, and periodically review

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and if necessary revise, NAAQS for ubiquitous air pollutants (sections 108 and 109). Congress required the States to submit SIPs to attain and maintain those NAAQS, and Congress included, in section 110, a list of minimum requirements that SIPs must meet. Congress anticipated that areas would attain the NAAQS by 1975.

In 1977, Congress amended the CAA by providing, among other things, additional time for areas that were not attaining the ozone NAAQS to do so, as well as by imposing specific SIP requirements for those nonattainment areas. These provisions first required the designation of areas as attainment, nonattainment, or unclassifiable, under section 107; and then required that SIPs for ozone nonattainment areas include the additional provisions set out in part D of title I, as well as demonstrations of attainment of the ozone NAAQS by either 1982 or 1987 (section 172).

In addition, the 1977 Amendments included two provisions focused on interstate transport of air pollutants: the predecessor to current section 110(a)(2)(D), which requires SIPs for all areas to constrain emissions with certain adverse downwind effects; and section 126, which, in general, authorizes a downwind State to petition EPA to impose limits directly on upwind sources found to adversely affect that State. Section 110(a)(2)(D), which is key to the present action, is described in more detail below.

b. 1990 CAA Amendments. In 1990, Congress amended the CAA to better address, among other things, continued nonattainment of the 1-hour ozone NAAQS; the requirements that would apply if EPA revised the 1-hour standard; and transport of air pollutants across State boundaries (Pub. L. 101–549, Nov. 15, 1990, 104 Stat. 2399, 42 U.S.C., 7401–7671q). Numerous provisions added, or revised, by the 1990 Amendments are relevant to today's proposal.

(1) 1-Hour Ozone NAAQS. In the 1990 Amendments, Congress required the States and EPA to review and, if necessary, revise the designation of areas as attainment, nonattainment, and unclassifiable under the ozone NAAQS in effect at that time, which was the 1- hour standard (section 107(d)(4)). Areas designated as nonattainment were divided into, primarily, five classifications based on air quality design values (section 181(a)(1)). Each classification carries specific requirements, including new attainment dates (sections 181–182). In increasing severity of the air quality problem, these classifications are marginal, moderate, serious, severe and extreme. The OTAG region includes nonattainment areas of all classifications except extreme.

As amended in 1990, the CAA requires States containing ozone nonattainment areas classified as moderate or above to submit several SIP revisions at various times. One set of SIP revisions included specified control measures, such as reasonably available control technology (RACT) for existing VOC and NO_X sources (section 182(b)(2), 182(f)). In addition, the CAA requires the reduction of VOC in the amount of 15 percent by 1996 from a 1990 baseline (section 182(b)(1)). Further, for nonattainment areas classified as serious and above, the CAA requires the reduction of VOC or NO_X emissions in the amount of 9 percent over each 3-year period from 1996 through the attainment date (the rate-of-progress (ROP) SIP submittals), under section 182(c)(2)(B). In addition, the CAA requires a demonstration of attainment, including air quality modeling, for the nonattainment area (the attainment demonstration), as well as SIP measures containing any additional reductions that may be necessary to attain by the applicable attainment date (section 182(c)-(e)). The CAA established November 15, 1994 as the required date for the ROP and attainment demonstration SIP submittals for areas classified as serious and above. [1]

(2) Revised NAAQS. Section 109(d) of the CAA requires periodic review and, if appropriate, revision of the NAAQS. As amended in 1990, the CAA further requires EPA to designate areas as attainment, nonattainment, and unclassifiable under a revised NAAQS (section 107(d)(1); section 6103, Pub. L. 105–178). The CAA authorizes EPA to classify areas that are designated nonattainment under the new NAAQS and to establish for those areas attainment dates that are as expeditiously as practicable, but not to exceed 10 years from the date of designation (section 172(a)).

(3) General Requirements. The CAA continues, in revised form, certain requirements, dating from the 1970 Amendments, which pertain to all areas, regardless of their designation. All areas are required to submit SIPs within certain timeframes (section 110(a)(1)), and those SIPs must include specified provisions, under section 110(a)(2). In addition, SIPs for nonattainment areas are generally required to include additional specified control requirements, as well as controls providing for attainment of any revised NAAQS and periodic reductions providing ''reasonable further progress'' in the interim (section 172(c)).

(4) Provisions Concerning Transport of Ozone and Its Precursors. The 1990 Amendments reflect general awareness by Congress that ozone is a regional, and not merely a local, problem. As described above, ozone and its precursors may be transported long distances across State lines to combine with ozone and precursors downwind, thereby exacerbating the ozone problems downwind. The phenomenon of ozone transport was not generally recognized until relatively recently. Yet, ozone transport is a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both Federal and State, across the country.

Section 110(a)(2)(D) provides one of the most important tools for addressing the problem of transport. This provision, which applies by its terms to all SIPs for each pollutant covered by a NAAQS, and for all areas regardless of their attainment designation, provides that a SIP must contain adequate provisions prohibiting its sources from emitting air pollutants in amounts that will contribute significantly to nonattainment, or interfere with maintenance, in one or more downwind States.

Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement. If EPA makes such a finding, it must require the State to submit, within a specified period, a SIP revision to correct the inadequacy.

The CAA further addresses interstate transport of pollution in section 126, which Congress revised slightly in 1990. Subsection (b) of that provision authorizes each State (or political subdivision) to petition EPA for a finding designed to protect that entity from upwind sources of air pollutants. [2]

In addition, the 1990 Amendments added section 184, which delineates a multistate ozone transport region (OTR) in the Northeast, requires specific additional controls for all areas (not only nonattainment areas) in that region, and establishes the Ozone Transport Commission (OTC) for the purpose of recommending to EPA regionwide controls affecting all areas in that region. At the same time, Congress added section 176A, which authorizes

[1] For moderate ozone nonattainment areas, the attainment demonstration was due November 15, 1993 (section 182(b)(1)(A)), except that if the State elected to conduct an urban airshed model, EPA allowed an extension to November 15, 1994.

[2] In addition, section 115 authorizes EPA to require a SIP revision when one or more sources within a State ''cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare in a foreign country.''

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the formation of transport regions for other pollutants and in other parts of the country.

2. Regulatory Structure

a. March 2, 1995 Policy. Notwithstanding significant efforts, the States generally were not able to meet the November 15, 1994 statutory deadline for the attainment demonstration and ROP SIP submissions required under section 182(c). The major reason for this failure was that at that time, States with downwind nonattainment areas were not able to address transport from upwind areas. As a result, in a memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, dated March 2, 1995, entitled ''Ozone Attainment Demonstrations,'' (March 2, 1995 Memorandum or the Memorandum), EPA recognized the efforts made by States and the remaining difficulties in making the ROP and attainment demonstration submittals. The EPA recognized that development of the necessary technical information, as well as the control measures necessary to achieve the large level of reductions likely to be required, had been particularly difficult for the States affected by ozone transport.

Accordingly, as an administrative remedial matter, the Memorandum indicated that EPA would establish new timeframes for SIP submittals. The Memorandum indicated that EPA would divide the required SIP submittals into two phases. Phase I generally consisted of (i) SIP measures providing for ROP reductions due by the end of 1999, (ii) an enforceable SIP commitment to submit any remaining required ROP reductions on a specified schedule after 1996, and (iii) an enforceable SIP commitment to submit the additional SIP measures needed for attainment. Phase II consists of the remaining submittals, beginning in 1997.

The Phase II submittals primarily consisted of the remaining ROP SIP measures, the attainment demonstration and additional rules needed to attain, and any regional controls needed for attainment by all areas in the region. The March 2, 1995 Memorandum indicated that the attainment demonstration, target calculations for the post-1999 ROP milestones, and identification of rules needed to attain and for post-1999 ROP were due in mid-1997. To allow time for States to incorporate the results of the OTAG modeling into their local plans, EPA extended the mid-1997 submittal date to April 1998.[3]

b. OTAG. In addition, the March 2, 1995 Memorandum called for an assessment of the ozone transport phenomenon. The Environmental Council of the States (ECOS) had recommended formation of a national work group to allow for a thoughtful assessment and development of consensus solutions to the problem. The OTAG was a partnership between EPA, the 37 easternmost States and the District of Columbia, industry representatives, and environmental groups. The OTAG's air quality modeling and recommendations formed the basis for today's action.

c. EPA's Transport SIP Call Regulatory Efforts. Shortly after OTAG began its work, EPA began to indicate that it intended to issue a SIP call to require States to implement the reductions necessary to address the ozone transport problem. On January 10, 1997 (62 FR 1420), EPA published a notice of intent that articulated this goal and indicated that before taking final action, EPA would carefully consider the technical work and any recommendations of OTAG. The EPA published the NPR for the NO_X SIP call by notice dated November 7, 1997 (62 FR 60319). The NPR proposed to make a finding of significant contribution due to transported NO_X emissions to nonattainment or maintenance problems downwind and to assign NO_X emissions budgets for 23 jurisdictions. The EPA published a supplemental notice of proposed rulemaking (SNPR) by notice dated May 11, 1998 (63 FR 25902) which proposed a model NO_X budget trading program and State reporting requirements and provided the air quality analyses of the proposed statewide NO_X emissions budgets. The EPA received approximately 700 comments on these proposals. The comment periods are described in Section I.F, Discussion of Comment Period and Availability of Key Information. Throughout the course of the rulemaking, EPA has added information to the docket. By notice dated August 24, 1998 (63 FR 45032), EPA published a notice of availability listing the additional documents placed in the docket.

d. Revision of the Ozone NAAQS. On July 18, 1997 (62 FR 38856), EPA issued its final action to revise the NAAQS for ozone. The EPA's decision to revise the standard was based on the Agency's review of the available scientific evidence linking exposures to ambient ozone to adverse health and welfare effects at levels allowed by the pre-existing 1-hour ozone standards. The 1-hour primary standard was replaced by an 8-hour standard at a level of 0.08 parts per million (ppm), with a form based on the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration measured at each monitor within an area. The new primary standard will provide increased protection to the public, especially children and other at-risk populations, against a wide range of ozone-induced health effects. Health effects are described in paragraph I.B, General Factual Background. The EPA retained the applicability of the 1-hour NAAQS for existing nonattainment areas until such time as EPA determines that an area has attained the 1-hour NAAQS (40 CFR 50.9(b)).

The pre-existing 1-hour secondary ozone standard was replaced by an 8-hour standard identical to the new primary standard. The new secondary standard will provide increased protection to the public welfare against ozone-induced effects on vegetation.

D. Section 126 Petitions

In a separate rulemaking, EPA is proposing action on petitions submitted by eight northeastern States under section 126 of the CAA. Each petition specifically requests that EPA make a finding that NO_X emissions from certain major stationary sources significantly contribute to ozone nonattainment problems in the petitioning State. The eight States are Connecticut, Massachusetts, Maine, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

Both the NO_X SIP call and the section 126 petitions are designed to address ozone transport through reductions in upwind NO_X emissions. However, the EPA's response to the section 126 petitions differs from EPA's action in the NO_X SIP call rulemaking in several ways. In today's NO_X SIP call, EPA is determining that certain States are or will be significantly contributing to nonattainment or maintenance problems in downwind States. The EPA is requiring the upwind States to submit SIP provisions to reduce the amounts of each State's NO_X emissions that significantly contribute to downwind air quality problems. The States will have the discretion to select the mix of control measures to achieve the necessary reductions. By contrast, under section 126, if findings of significant contribution are made for any sources identified in the petitions, EPA would determine the necessary emissions

[3] Guidance for Implementing the 1-hour Ozone and Pre-Existing PM10 NAAQS, Memorandum from Richard D. Wilson, dated December 29, 1997.

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limits to address the amount of significant contribution and would directly regulate the sources. A section 126 remedy would apply only to sources in States named in the petitions.

Based on the view that the SIP call and section 126 petitions are both designed to achieve the same goal, several commenters urged EPA to coordinate the two actions to the maximum extent possible. The EPA agrees that the two actions are closely related and, therefore, should be coordinated. This will help provide certainty for State and business planning requirements. In addition, this coordination can help to facilitate a trading program among sources in SIP call States that choose to participate in the NO_X trading program, and any section 126 sources that would be subject to a Federal NO_X trading program.

The section 126 provisions require that any control remedy be implemented within 3 years from the date of the finding that major sources or a group of stationary sources emit or would emit in violation of the relevant prohibition in section 110(a)(2)(D). Under EPA's anticipated rulemaking schedule [4] on the petitions, the compliance date for sources for which EPA makes such a finding could be April 30, 2002; November 30, 2002; or May 1, 2003. Several commenters expressed concern that the compliance deadline under section 126 was driving EPA's decision on the compliance deadline for the NO_X SIP call. Therefore, they believed that no changes would be made in the proposed NO_X SIP call deadline in response to comments.

While EPA believes it is advantageous to coordinate the section 126 and NO_X SIP call actions, EPA disagrees that this constrains EPA from being responsive to public comments and considering alternative compliance dates. See discussion below in Section V, NO_X Control Implementation and Budget Attainment Dates.

In the NO_X SIP call NPR, EPA proposed that States be required to submit SIPs within 12 months of the final SIP call. One commenter asserted that the timing and terms of the rulemaking schedule for the section 126 petitions precludes EPA from considering public comments advocating different SIP due dates for the NO_X SIP call. The section 126 rulemaking schedule provides several options. One option would allow findings on the petitions to be deferred pending certain actions by the States and EPA on State submittals in response to the NO_X SIP call. The premise for the specified schedule is that the SIP due date would be September 30, 1999 (i.e., roughly 12 months from signature of the notice on the final NO_X SIP call). As discussed below in Section VI, SIP Revision Criteria and Schedule, EPA continues to believe 12 months is an appropriate timeframe. However, had EPA determined that a longer timeframe for SIP submittal was warranted, the section 126 rulemaking schedule would not have restricted EPA from establishing a later due date.

One commenter supported the section 126 rulemaking schedule because they thought it had the effect of using the SIP process rather than the source-based petitions in that it provides an option of deferring section 126 findings if EPA approves a State's NO_X SIP. Another commenter thought that the conditions for deferring section 126 findings were too stringent, and, therefore, section 126 would inevitably be triggered prior to approval of any SIP provisions. This issue is discussed in detail in Section II.A.2.c. in the NPR EPA just issued on the section 126 petitions, which appears in the docket.

E. OTAG

As discussed in the proposed SIP call, OTAG completed the most comprehensive analyses of ozone transport ever conducted. The EPA participated extensively in this process. The EPA believes that the OTAG process was successful and generated much useful technical and modeling information on regional ozone transport. This information provided EPA with the foundation for this rulemaking.

The EPA received numerous comments regarding the relationship between the OTAG recommendations and EPA's proposed SIP call. Some commenters asserted that the Agency's proposal was inconsistent with the OTAG recommendations, while others believed that EPA used the information and recommendations from OTAG appropriately. Primarily, commenters stated that OTAG recommended a range of controls for utility sources instead of a uniform level of control for all of the included States.

The OTAG did recommend consideration of a range of controls, and although it did not specifically recommend uniform controls across a broad region, such a control scheme is within the range of its recommendation. The EPA's action today is based on its consideration of OTAG's recommendations, as well as information resulting from EPA's additional work, and extensive public input generated through notice-and-comment rulemaking. The EPA continues to believe, for reasons explained in Section III.F.1, Uniform vs. Regional Controls, that requiring NO_X emissions reductions across the region in amounts achievable by uniform controls is a reasonable, cost-effective step to take at this time to mitigate ozone nonattainment in downwind States for both the 1-hour and 8-hour standards.

Commenters also stated that EPA applied an electric utility control level that was more stringent than the upper limit of the OTAG range of utility controls. The OTAG recommended a range of utility controls that falls between specific CAA-required controls and the less stringent of 85 percent reduction from the 1990 rate (lb/mmBtu), or 0.15 lb/mmBtu. In determining the appropriate level of emissions reductions, EPA considered what levels of NO_X reductions could be obtained by applying, to various source sectors, controls that are among the most cost effective and feasible with today's proven pollution control technologies. The EPA chose emissions reductions that are equivalent to an emission limit from utilities of 0.15 lb/mmBtu. The EPA acknowledges that this level may be more protective than the most protective level contained in the OTAG recommendation in some cases, but, as discussed below in Section IV, Air Quality Assessment, EPA believes that it provides the most improvement in air quality while staying within the bounds of the most highly cost-effective technology available. (Cost effectiveness is discussed in Section II.D.) In addition, by relying on actual 1995–1996 continuous emission monitoring data, rather than relying on estimated 1990 emission data, this approach provides a more accurate way of determining the States' budgets since it minimizes any chances of over-or under-estimation of emissions.

Commenters asserted that OTAG recommended 12 months for additional modeling—especially subregional modeling—before promulgating the SIP call; and these commenters expressed concern that EPA did not provide this amount of time following publication of the NPR. As discussed in more detail in Section I.F, Discussion of Comment Period and Availability of Key

[4] The eight northeastern States that filed section 126 petitions also filed suit in the District Court for the Southern District of New York, to compel EPA to take action on those petitions within prescribed periods. *State of Connecticut* v. *Browner,* No. 98–1376 (S.D.N.Y., filed Feb. 25, 1998). The EPA and the eight northeastern States jointly filed a motion to enter a consent order prescribing certain dates for EPA action.

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Information, the Agency ultimately provided approximately 1 year from the conclusion of OTAG for States and other members of the public to complete and submit subregional and other types of modeling. The EPA has considered this additional modeling in finalizing today's rule.

Some commenters stated that the goal of OTAG was to address attainment of the ozone NAAQS. This is incorrect. The OTAG's goal was to reduce ozone transport, which is one of the steps necessary to enable attainment; the goal was not to recommend an overall strategy that would yield attainment through regional measures alone. The OTAG articulated its overall goal as follows:

> * * * identify and recommend a strategy to reduce transported ozone and its precursors which, in combination with other measures, will enable attainment and maintenance of the national ambient ozone standard in the OTAG region. A number of criteria will be used to select the strategy including, but not limited to, cost effectiveness, feasibility, and impacts on ozone levels. [5]

It is also EPA's goal to ensure that sufficient regional reductions are achieved to mitigate ozone transport in the eastern half of the United States and thus, in conjunction with local controls, enable nonattainment areas to attain and maintain the ozone NAAQS.

Commenters indicated that OTAG focused only on the 1-hour standard nonattainment problem and did not assess compliance implications of the 8-hour standard. For this reason, according to commenters, EPA should not base today's action on the nonattainment of the 8-hour NAAQS. It is true that OTAG was established to address transport issues associated with meeting the 1-hour standard. The EPA did not promulgate the 8-hour standard until shortly after OTAG concluded; thus, OTAG did not recommend strategies to address the 8-hour NAAQS. However, because EPA had proposed an 8-hour standard, OTAG did examine the impacts of different strategies on 8-hour average ozone predictions.

In light of OTAG's work and additional information, EPA is able to assess ozone transport as it relates to the 8-hour NAAQS and to set forth requirements as necessary to address the 8-hour standard in this rulemaking. Ozone transport causes problems for downwind areas under either the 1-hour or 8-hour standard. The regional reductions of NO_X that will be achieved through this SIP call for the 1-hour NAAQS are key components for meeting the new 8-hour ozone standard in a cost-effective manner. Therefore, EPA believes that the OTAG recommendations for how to address ozone transport are valid for both NAAQS.

Several commenters urged EPA to adopt and implement all Federal measures identified in the OTAG recommendations. [6] The Agency is committed to continue implementing national control measures for NO_X, as recommended by OTAG. In addition, EPA has adopted the following national measures for purposes of reducing VOC: architectural and industrial maintenance coatings, consumer/commercial products, and autobody refinishing. The EPA has made no decisions regarding further VOC reductions beyond the reductions specified as phase I in the OTAG recommendations. [7]

Other more specific comments concerning the OTAG recommendations will be addressed throughout this rulemaking as the issues are discussed.

F. Discussion of Comment Period and Availability of Key Information

The EPA received numerous comments concerning the adequacy of the comment period for the November 7, 1997 NPR and May 11, 1998 SNPR. Some commenters remarked that the comment period for the NPR should be extended to allow for development and review of technical information, including inventory data, growth factors, and the resulting budget. Commenters stated that the additional time was particularly necessary for subregional air quality modeling, which is modeling designed to isolate the impacts of emissions from a particular State or group of States on downwind areas. Many specifically requested an additional 120 days, and one requested an additional 9 months. Some commenters indicated that EPA did not incorporate their comments from the NPR into the SNPR. Other commenters insisted that key information supporting the rule is not publicly available. The EPA also received comments that additional public hearings should be held in other locations of the OTAG region.

1. Request for Extension of the Comment Period

The EPA allowed a 120-day public comment period for the November 7, 1997 NPR, which closed on March 9, 1998. By notice (63 FR 17349, April 9, 1998), EPA reopened the comment period for members of the public to submit additional modeling analyses, as well as comments concerning the implications that any additional modeling may have for the State NOx budgets under consideration in the November 7, 1997 proposal. The comment period was reopened through the end of the comment period on the SNPR. The SNPR, which was published on May 11, 1998, allowed a comment period until June 25, 1998. Thus, for most issues addressed in the NPR, including air quality modeling issues, commenters received an almost 8-month formal comment period. Indeed, many commenters had access to the NPR immediately after October 10, 1997, when it was signed and posted on an EPA website. The Agency also received a number of comments after June 25, 1998, which were also reviewed and considered in developing the final rule.

The EPA believes this additional opportunity for the public to submit comments was reasonable. After March 9, 1998—the initial date for close of the comment period on the NPR—EPA received numerous comments on various issues raised in the NPR, including air quality issues. Many of these comments were extensive, which indicates that commenters received adequate time.

With respect to the concern that EPA did not incorporate comments received on the NPR into the SNPR, it would not have been practical for EPA to incorporate comments received on the NPR into the SNPR because the SNPR was completed soon after the close of the comment period for the NPR. In general, the SNPR addressed different aspects of the rule than the NPR, and one of the purposes of the SNPR was to take comment on several new issues, as noted above. The EPA has addressed comments on both the NPR and SNPR in today's action.

The major issues raised in the comments are responded to throughout the preamble of this final rule. A comprehensive summary of all significant comments, along with EPA's response to the comments which have not been responded to in the preamble (Response to Comments), can be found in the docket for this rulemaking (Docket No. A–96–56).

[5] Ozone Transport Assessment Group Policy Paper approved by the Policy Group on December 4, 1995.

[6] The OTAG recommendations are located in Appendix B of the November 7, 1997 NPR (62 FR 60376).

[7] Letter to the Honorable Ken Calvert, Chairman, Subcommittee on Energy and Environment, U.S. House of Representatives, from Robert D. Brenner, Acting Deputy Assistant Administrator for Air and Radiation, U.S. EPA, June 26, 1998, transmitting EPA's responses to questions following the May 20, 1998 congressional hearing on EPA's proposed rule on paints and coatings.

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2. Request for Time to Conduct Additional Modeling

The OTAG Policy Group, at its June 3, 1997 meeting, recommended that States have the opportunity to conduct additional local and subregional modeling and air quality analyses, as well as to develop and propose appropriate levels and timing of controls. The EPA received numerous comments related to OTAG's recommendation. The commenters requested that the Agency give States more time to conduct this additional modeling so that EPA could more accurately assess each State's contribution to downwind nonattainment.

The EPA signed the NPR on October 10, 1997, and posted it on a website at that time, although it was not published in the **Federal Register** until November 7, 1997. As noted above, EPA reopened the comment period through June 25, 1998 for submittal of additional air quality modeling runs. In effect, this has extended the amount of time for modeling analyses to over a year from the date OTAG submitted its recommendations, and to over 8 months from the signature date for the NPR. By the close of the comment period on June 25, 1998, EPA had received numerous comments containing new and extensive air quality modeling studies. Accordingly, EPA believes that commenters received adequate time.

3. Availability of Key Information

A number of commenters asserted that EPA failed to make publicly available key information, such as modeling and emissions inventory data. Specifically, commenters stated that they did not have access to the emissions data on which EPA based the air quality modeling for the NPR. In addition, according to some commenters, several models used by EPA and OTAG are proprietary models and have not been generally available to the public.

In Section III.A.2, Availability, the Agency discusses the availability of emissions inventory data to the public.

The OTAG and EPA conducted air quality modeling runs to determine the level of contribution from emissions in upwind areas to ozone nonattainment in downwind areas. Some of this modeling employed UAM–V.[8] The UAM–V has generally been available to the public for the purpose of analyzing information relevant to today's rulemaking. State and local agencies, as well as utility companies and other stakeholders, have had access to licenses to use UAM–V.

Commenters objected that they were obliged either to purchase licenses for use of the UAM–V model or to employ as a contractor the model owner, and that these financial constraints restricted their access to the model. Because this model has, in general, been privately developed, EPA believes that reasonable fees for its use should be expected. The EPA did not receive information indicating that the associated expenses were other than reasonable. To the extent that commenters experienced delays in obtaining the UAM–V model, EPA believes that the extensions of the comment period resulted in adequate time for comment. In any event, any commenter who was not able to gain access in the timeframe desired was able to use a comparable model, such as the Comprehensive Air Quality Model with Extensions (CAMx), which is not proprietary. For the purpose of responding to public comments, EPA is considering all information based on CAMx and similar models.

The Agency made available additional modeling runs used to determine emissions changes, costs and cost effectiveness for electricity generating units (EGUs). These runs were placed on the IPM Analyses web site at www.epa.gov/capi, with links to EPA's Office of Air and Radiation Policy and Guidance web site.

On August 10, the EPA placed in the docket and made available on the web site, modeling analyses and other information supporting today's action. As noted above, by notice dated August 24, 1998 (63 FR 45032), EPA published a notice of availability which stated that throughout the course of the rulemaking, EPA had placed information in the docket or made it available on various web sites. This information included inventory data and additional modeling runs. By placing those materials in the docket and informing the public of their availability, EPA provided 4–6 weeks for review and comment by the public. The EPA did receive comments concerning this information from the Utility Air Regulatory Group on September 9, and EPA is responding to those comments in the Response To Comments document. The EPA notes that the additional modeling analyses were performed in response to comments received on the NPR urging EPA to conduct State-by-State modeling. The Agency does not believe it is required to provide for additional comment on every action it takes in response to comment, particularly where, as here, the new information confirms the Agency's proposed conclusions. Therefore, the Agency did not further extend the comment period.

4. Public Hearings

The Agency conducted two hearings in Washington, DC, including a 2-day hearing on February 3–4, 1998 for the NPR, and a 1-day hearing on May 29, 1998 for the SNPR. Some commenters believe that additional public hearings should have been held in other locations in the OTAG region. The EPA believes these hearings provided reasonable opportunity for oral comment on the proposed rulemaking given the timeframes associated with this rulemaking. Therefore, the Agency did not schedule any additional hearings. The public also had an opportunity to submit written testimony within approximately 30 days after each hearing date.

G. Implementation of Revised Air Quality Standards

On July 18, 1997, EPA published its final rule for strengthening the NAAQS for ozone by establishing an 8-hour standard (62 FR 38856). Current monitoring data indicate that many areas in the East, Midwest and South violate the 8-hour NAAQS. Along with areas violating the 1-hour NAAQS, areas violating the 8-hour NAAQS are also affected by the transport of ozone across the East. The regional NO_X reduction strategy finalized in today's action will provide a mechanism to achieve reductions that will assist States in attaining and maintaining this revised standard. In fact, the regional reductions alone should be enough to enable the vast majority of the new counties violating the 8-hour NAAQS that are located in States throughout the East to attain the revised 8-hour standard.[9]

On July 16, 1997, President Clinton issued a directive on the implementation of the revised air quality standards. This implementation policy was described in the NPR (62 FR 60318, 60362–64). The EPA received numerous comments on this implementation policy and on EPA's plan to create a transitional classification[10] for 8-hour ozone nonattainment areas that meet certain

[8] Variable-Grid Urban Airshed Model.

[9] In the NPR (62 FR 60318, 60363), EPA provided estimates of the number of counties expected to attain as a result of the NO_X SIP call. The EPA will update this list in the coming months. The updated estimates of which counties will attain will be based on more current air quality data and on the State-by-State emissions budgets contained in today's final rule.

[10] The ''transitional classification'' EPA intends for 8-hour ozone nonattainment areas is further discussed in the NPR (62 FR 60318, 60363).

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criteria. Since these comments concern implementation efforts for the revised 8-hour ozone standard and do not relate directly to the NO_X SIP call on which EPA is taking final action in this rulemaking, EPA is not responding in detail to the comments. The EPA will address implementation of the revised standard separately. In August 1998, EPA issued proposed guidance for public comment to explain the implementation policy in further detail and to provide details on SIP requirements for transitional areas (63 FR 45060, August 24, 1998). The EPA expects to finalize the August 1998 draft guidance, as well as guidance for areas other than transitional, by December 1998. [11]

H. Summary of Major Changes Between Proposals and Final Rule

This summary describes the major changes that have occurred since the NPR and SNPR in each of the following sections of today's final rule.

1. EPA's Analytical Approach (Section II.A)

- The NPR proposed two interpretations for the section 110(a)(2)(D)(i)(I) provisions concerning the ''significant contribution'' test. Under the first, EPA would examine certain factors relating to level of emissions and their ambient impact to determine whether to make a finding that all of the emissions from a particular State's sources contribute significantly to nonattainment or maintenance problems downwind. If EPA made such a finding, then EPA would examine certain cost factors to determine the extent to which the SIP for the State must mitigate (reduce) its emissions. Under the second interpretation, EPA would examine all of those factors together—level of emissions, ambient impact, and costs—to determine whether to make the finding with respect to a specified amount of emissions. If EPA made the finding, then it would require the SIP to eliminate that amount. In today's final rule, EPA is adopting the second interpretation. The EPA indicates, however, that it would adopt the same rule if it were instead implementing the first interpretation.

2. Cost Effectiveness of Emissions Reductions (Section II.D.)

- The methodology of determining cost effectiveness has not changed. For all sources, the inventory and as a result, the source-specific costs, in some cases, have changed. This results in a different overall budget level and a different overall cost-effectiveness value. For the non-EGUs, while the methodology has not changed, the analysis focuses on large non-EGU sources. The methodology in the NPR focused on all non-EGU sources.

3. Determination of Budgets (Section III.)

- For EGU, the EPA maintained the approach to use the higher, by State, of 1995 or 1996 heat input data to calculate baseline heat input rates for the NFR, and added 577 smaller units to the State budget inventories which had erroneously been omitted from the NPR. These units included electricity generating sources of 25 megawatts (MW) or less of electrical output and additional units not affected under the Acid Rain Program. Additional controls are not assumed for these sources, but they are added to the budget at baseline levels. The Agency has decided to use State-specific growth factors derived from application of the IPM using the 1998 Base Case and chose to retain the 0.15 lbs/mmBtu as the assumed uniform control level for EGU budget emissions determination.
- The EPA examined alternatives that focus on non-EGU point source reductions from the largest source categories, and within each of these categories assumed controls that would result in a regionwide average cost effectiveness less than $2000/ton. The resulting budget assumes the emissions reductions from large non-EGU sources that are among the most cost effective to control and does not include reductions from smaller sources and sources that, as a group, are not quite as cost effective or efficient to control, or are already covered by other Federal measures. As a result, this final rule assumes, for purposes of calculating the State NO_X budgets, the following emissions decreases from uncontrolled levels for the large (generally greater than 250 mmBtu or 1 ton/day non-EGU sources (no emission reductions are assumed for the smaller sources):

—Non-EGU boilers and turbines—60 percent decrease.
—Stationary internal combustion engines—90 percent decrease.
—Cement manufacturing plants—30 percent decrease.

It should be noted that point sources with capacities less than 250 mmBtu/hr but with emissions greater than 1 ton/ day are not treated differently from sources with capacities greater than 250 mmBtu/hr for purposes of calculating the budget. This is a change from the NPR which included RACT controls on units with capacities less than 250 mmBtu/hr and emissions greater than 1 ton/day (see Section III.G.2.a). As under the proposal, the rule allows States to choose control measures other than the EPA-assumed controls to meet the numerical budgets.

- The EPA has implemented the following changes that the Agency proposed in the NPR for calculating baseline NO_X emissions from highway vehicles. A 1995 baseline is used for the final rule in place of the 1990 baseline used in the NPR. The Highway Performance and Monitoring System data were used to estimate States' 1995 vehicle miles traveled (VMT) by vehicle category, except in those cases where EPA accepted revisions offered in the comments. Today's action includes those mobile source reductions which EPA has determined are appropriate to implement on a national basis, and which have been promulgated in final form or are expected to be promulgated in final form before States are required to comply with their budgets. The highway vehicle budget components include the emission reductions resulting from implementation of the National Low Emitting Vehicle (NLEV) program, including the phase-in schedule agreed to by the States, automobile manufacturers, and EPA. The highway budget components do not include the effect of Tier 2 light-duty vehicle and truck standards and any associated fuel standards since these standards have not yet been proposed. The extent of the reformulated gasoline (RFG) and inspection and maintenance (I/M) programs was not assumed to change beyond that assumed for the NPR, except for those States that were able to demonstrate that the NPR's modeling assumptions did not conform to the State's SIP and did not reflect CAA requirements.
- The EPA has chosen to retain the 1990 baseline inventories for nonroad mobile sources presented in the NPR for today's action, with additional changes made in response to public comments. The control strategies assumed for calculating the nonroad and stationary area source budget components have not changed from the SNPR.

4. NO_X Control Implementation and Budget Achievement Dates (Section V)

- The EPA proposed that the SIP revisions require full implementation of the necessary State measures by September 2002 and took comment on a range of dates from September 2002 through September 2004. Based on

[11] For a complete listing of the guidance and other actions EPA plans to issue to implement the revised ozone and PM NAAQS, see a table on EPA's implementation website: http://ttnwww.rtpnc.epa.gov/implement/actions.htm.

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public comments and feasibility analyses conducted by EPA, the Agency is requiring an implementation date of May 1, 2003. The Agency is also providing some compliance flexibility to States for the 2003 and 2004 ozone seasons by establishing State compliance supplement pools. This is described in Section III.F.6.

5. SIP Criteria (Section VI.A)

• The Agency has determined that the additional SIP approvability criteria, as proposed in the SNPR, should apply not only when States choose to regulate EGUs (63 FR 25912), but also when States choose to regulate large steam-producing units (i.e., combustion turbines and combined cycle systems with a capacity greater than 250 mmBtu/hr).

• The Agency proposed revisions to part 51 requiring continuous emissions monitoring systems (CEMS) on all large electrical generating and steam-producing sources which States elect to subject to emissions reduction requirements in response to this rulemaking. The EPA took comment on requiring that, if a State chooses to regulate these sources to meet the SIP call, the SIP must require these sources to use the NO_X mass monitoring provisions of part 75, subpart H, to demonstrate compliance with applicable emissions control requirements. After considering comments, the Agency is requiring that, in these circumstances, the SIP specify that large sources comply with the monitoring provisions of part 75, subpart H, which includes non-CEMS monitoring options for units that are infrequently operated or units that have low mass emissions.

6. Emissions Reporting Requirements for States (Section VI.B)

• The proposed rule required that States report full-year, as well as ozone-season, emissions from all sources for the triennial inventories commencing with year 2002 emissions and the 2007 inventory, and for those sources for which reports had to be submitted annually starting with year 2003 emissions. The final rule requires only ozone-season emissions reporting for all sources.

• In the SNPR, the EPA proposed, for purposes of reporting requirements, to define a point source as a non-mobile source which has NO_X emissions of 100 tons/year or greater. Under today's action, States have the option of establishing a smaller emission threshold than 100 tons/year of NO_X emissions in defining point source. This will allow the definition of point source to remain consistent with current definitions in local areas.

7. NO_X Budget Trading Program (Section VII.)

• For States that choose to participate in the NO_X Budget Trading Program, the preamble clarifies the intent of the model rule and identifies areas of the rule where States have flexibility to include variations in their State rules.

• In the SNPR, the Agency solicited comment on a range of options for incorporating banking into the trading program. After considering these comments, the Agency is including banking provisions in the final rule. The provisions allow for unlimited banking starting in 2003 and includes a flow control mechanism to limit the emissions variability associated with banking.

• One of the banking approaches presented in the SNPR included the option for sources to generate and use early reduction credits. Consistent with the provisions of the NO_X SIP call which provide for State compliance supplement pools, the final rule allows States to issue early reduction credits for certain NO_X emissions reductions achieved between September 30, 1999 and May 1, 2003.

• The final rule clarifies the timing requirements for State submission of allowance allocations to EPA and, as proposed, lays out an allocation approach. Each State remains free to adopt the final rule's allocation approach or adopt an allocation scheme of its own, provided it meets the specified timing requirements, requires new sources to hold allowances, and does not allocate more allowances than are available in the State trading budget.

8. Interaction with Title IV NO_X Rule (Section VIII.)

• In the SNPR, EPA proposed revisions to part 76 addressing the interaction between title IV and the NO_X SIP call. In this final rule, EPA explains that the Agency is not adopting any of the proposed revisions to part 76.

9. Administrative Requirements (Section X.)

• NPR Section VIII, Regulatory Analyses, has been replaced in the final rule by Section X.A, Executive Order 12866: Regulatory Impacts Analysis. The new final rule Section X.A indicates that EPA has prepared a RIA for the final rule and cites the cost and benefit estimates from that analysis.

• The final rule adds several Sections under X, Administrative Requirements, that were absent from the NPR. These include: Paperwork Reduction Act; Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks; Executive Order 12898: Environmental Justice; Executive Order 12875: Enhancing the Intergovernmental Partnerships; Executive Order 13084: Consultation and Coordination with Indian Tribal Governments; Judicial Review; and Congressional Review Act. These new Sections provide a more comprehensive summary of the Acts and Executive Orders that could apply to the final rule. Each Section identifies the requirements of the relevant Act or Executive Order, indicates EPA's interpretation of whether the Act or Executive Order actually applies to this rulemaking, and, if so, indicates how the Agency has addressed the Act or Executive Order.

II. EPA's Analytical Approach

A. Interpretation of the CAA's Transport Provisions

As indicated in the NPR, 62 FR 60323, the primary statutory basis for today's action is the ''good neighbor'' provision of section 110(a)(2)(D)(i)(I), under which, in general, each SIP is required to include provisions assuring that sources within the State do not emit pollutants in amounts that significantly contribute to nonattainment or maintenance problems downwind. This statutory requirement applies to SIPs under both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS.

1. Authority and Process for Requiring SIP Submissions Under the 1-Hour Ozone NAAQS

a. Authority for Requiring SIP Submissions under the 1-Hour NAAQS. Each State is currently required to have in place a SIP that implements the 1-hour ozone NAAQS for areas to which that standard still applies. In the NAAQS rulemaking, EPA determined that the 1-hour NAAQS would cease to apply to areas that EPA determines have air quality in attainment of that NAAQS (40 CFR 50.9(b)). In two recent rulemakings, EPA identified numerous areas of the country to which the 1-hour NAAQS no longer applies. ''Final Rule: Identification of Ozone Areas Attaining the 1-Hour Standard and to Which the 1-Hour Standard is No Longer Applicable,'' (63 FR 31014, June 5, 1998); ''Final Rule: Identification of Additional Ozone Areas Attaining the 1-Hour Standard and to Which the 1-Hour Standard is No Longer Applicable,'' (63 FR 27247, July 22, 1998).

The 1-hour NAAQS remains applicable to areas whose air quality continues to monitor nonattainment. As noted above in Section I.B, General

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Factual Background, these include many major urban areas in the eastern half of the United States. States that contain these areas remain responsible for meeting CAA requirements applicable to those areas for the purpose of attaining the 1-hour NAAQS. For example, States are responsible for attainment demonstrations for areas designated nonattainment and classified as moderate or higher.

By the same token, States that are upwind of these areas are responsible to meet the ''good neighbor'' requirements of section 110(a)(2)(D). This responsibility is not alleviated simply because, for areas other than the current nonattainment areas, the 8-hour NAAQS has replaced the 1-hour NAAQS.

b. Process for Requiring SIP Submissions under the 1-Hour NAAQS. As explained in the NPR, the appropriate route for EPA to require SIP submissions under section 110(a)(2)(D)(i)(I) with respect to the 1-hour standard is issuance of a ''SIP call'' under section 110(k)(5).[12] Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet a CAA requirement and to require (''call for'') the State to submit, within a specified period, a SIP revision to correct the inadequacy. Specifically, section 110(k)(5) provides, in relevant part:

> Whenever the Administrator finds that the applicable implementation plan for any area is substantially inadequate to attain or maintain the relevant [NAAQS], to mitigate adequately the interstate pollutant transport described in section 176A or section 184, or to otherwise comply with any requirement of this Act, the Administrator shall require the State to revise the plan as necessary to correct such inadequacies. The Administrator shall notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions.

By today's action, EPA is determining that the SIPs for the specified jurisdictions are substantially inadequate to comply with the requirements of section 110(a)(2)(D)(i)(I) because the relevant SIPs do not contain adequate provisions prohibiting their sources from emitting amounts of NO_X emissions that contribute significantly to nonattainment in downwind areas that remain subject to the 1-hour NAAQS. Based on these determinations, EPA is requiring the identified States to submit SIP revisions containing adequate provisions to limit emissions to the appropriate amount.

If a State does not submit the required SIP provisions in response to this SIP call, EPA will issue a finding that the State failed to make a required SIP submittal under section 179(a). This finding has implications for sanctions as well as for EPA's promulgation of Federal implementation plans (FIPs). Sanctions and FIPs are discussed in Section VI, SIP Criteria and Emissions Reporting Requirements.

(1) Commenters' Arguments Concerning the Transport Provisions. Commenters argued that EPA does not have unilateral authority to issue a SIP call under section 110(k)(5) to require States to remedy SIPs that do not meet the requirements of section 110(a)(2)(D). The commenters noted that when Congress amended the CAA in 1990, Congress provided that the sole authority for EPA and States to address interstate transport of pollution is through transport commissions. In support, the commenters state that Congress: (i) Added sections 176A and 184, which authorize the establishment of transport regions and the formation of transport commissions; (ii) revised section 110(k)(5) to refer to those transport provisions; and (iii) revised section 110(a)(2)(D)(i) to require that SIP provisions designed to eliminate interstate pollutant transport be consistent with other CAA requirements. According to the commenters, these provisions, read as a whole, mandate that if EPA believes that a transport problem exists, EPA's sole recourse is to form a transport region under sections 176A and/or 184; EPA may issue a SIP call to mandate compliance with section 110(a)(2)(D)(i) only in response to a recommendation of the transport region. The commenters also claim that this scheme is sensible because it provides a consensual forum for States to address interstate pollution rather than allowing unilateral action on the part of EPA or a State.

The EPA disagrees with the commenters' conclusion that these statutory provisions make clear that EPA cannot require a State to address interstate transport without first establishing a transport commission and in the absence of a recommendation from the transport commission. There is no language of limitation in sections 110(a)(2)(D) or (k)(5), or 176A, or 184. Nor is there any support in the legislative history for such a narrow reading of the statute. Moreover, under the commenters' interpretation, the CAA Amendments of 1990 have placed greater constraints on States' and EPA's ability to address the interstate transport of pollution. Such an interpretation would be inconsistent with the overall purpose of the CAA to ensure healthful air. Thus, EPA believes that the transport provisions were added as an additional tool to address interstate transport but were not intended to preclude other methods of addressing interstate pollution than prior to passage of the amendments.

Under the 1990 Amendments, Congress recognized the growing evidence that ozone and its precursors can be transported over long distances and that the control of transported ozone was a key to achieving attainment of the ozone standard across the nation (Cong. Rec. S16903 (daily ed. Oct. 27, 1990) (statement of Sen. Mitchell); S16970 (conference report) S16986–87 (statement of Sen. Lieberman)). Thus, in 1990, Congress added a new mechanism to address interstate transport. Specifically, Congress enacted sections 176A and 184, which provide a mechanism for States to work together to address the interstate transport problem. However, by their terms, these sections simply provide authority for EPA to designate transport regions and establish transport commissions. There is nothing in the language of these provisions that indicates that they supersede the other statutory mechanisms for addressing interstate transport, or that they now provide the sole mechanism for resolving interstate pollution transport.

Moreover, although Congress expressly added these two provisions through the 1990 Amendments, Congress did not in any way limit section 110(a)(2)(D), which requires States to address interstate transport in their SIPs. The addition of the language providing that States' actions under section 110(a)(2)(D) be ''consistent with [title I] of the Act'' cannot be read to limit the controls States may adopt to meet section 110(a)(2)(D) to those recommended by a transport commission.[13] After all, the transport region provisions are only two of many provisions in title I. Rather, this

[12] As discussed in the NPR and in greater detail further below, the basis for requiring a transport-related SIP revision for the 8-hour standard is the requirement in section 110(a)(1) that States submit SIPs meeting the requirements of section 110(a)(2) within 3 years (or an earlier date established by EPA) of promulgation of a new or revised NAAQS. This is discussed in further detail below.

[13] Taken to its logical conclusion, the commenters' argument would mean that States are precluded from submitting a section 110(a)(2)(D) SIP unless it reflects measures recommended through the transport commission process. The EPA does not believe that Congress would first establish a specific mandate (to submit a SIP to address interstate transport) and then limit it in such a cryptic fashion. If Congress intended section 110(a)(2)(D) SIPs to only reflect transport commission recommendations, Congress could have specifically referenced sections 176A and 184 in section 110(a)(2)(D), rather than generally providing that SIPs be ''consistent'' with title I of the CAA.

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language concerning consistency should be read as clarifying that any section 110(a)(2)(D) requirement must be consistent with other provisions of title I. Similarly, this language makes explicit that SIP revisions required in accordance with the procedures of the transport provisions would meet the requirements of section 110(a)(2)(D)(i).

Furthermore, it is significant that Congress did not in any sense bind EPA's ultimate discretion to determine whether State plans appropriately address interstate transport. Under sections 176A and 184, the States may only make recommendations to EPA. Thus, under the transport provisions, as well as the general SIP requirements of section 110(a)(2), EPA must ultimately decide whether the SIP meets the applicable requirements of the CAA. If, as the commenters contend, EPA is limited to calling on States to address interstate transport only by strategies recommended by the State, then EPA would be precluded from ensuring that States address interstate transport. For example, EPA could establish a transport commission but the commission could fail to make recommendations or make insufficient recommendations. (Section 176A provides that transport commissions may make recommendations to EPA only by ''majority vote of all members'' other than those representing EPA.) Such a reading of the statute would be absurd in light of the growing recognition at the time of the 1990 Amendments that transport is a real threat to the primary purpose of title I of the CAA—attainment of the NAAQS.

By the same token, in amending section 110(k)(5) in the 1990 Amendments, Congress did not add anything that explicitly provides that, in the case of interstate transport, section 110(k)(5) would apply only when EPA approved (or substituted measures for) a transport commission's recommendations. The reference in section 110(k)(5) to the transport provisions of sections 176A and 184 does not preclude EPA's use of the SIP call provision to call on States to ensure their SIPs meet the requirements of section 110(a)(2)(D)(i). Section 110(k)(5) also provides for EPA to call on States ''to otherwise comply with requirements of this Act;'' among the requirements in chapter I of the CAA is the requirement in section 110(a)(2)(D). The reference in section 110(k)(5) to the transport provisions simply makes explicit that EPA may employ section 110(k)(5) for the additional purpose of requiring SIPs to include the control measures as recommended by transport commissions and approved by EPA under the transport provisions.

Moreover, there is no indication in the legislative history of the 1990 Amendments that Congress intended the sections 176A and 184 transport provisions to supersede the section 110(k)(5) SIP call mechanism for ensuring compliance with section 110(a)(2)(D)(i). Reading the transport provisions to supersede the SIP call mechanism would constitute a significant change from the CAA as it read prior to the 1990 Amendments. Even if the statute is ambiguous as to whether the transport provisions supersede the SIP call mechanism—and EPA believes the statute is clear that the transport provisions do not supersede— congressional silence would suggest that Congress did not intend such a significant change (See generally *Harrison* v. *PPG Industries, Inc.* , 446 U.S. 578, 602, 100 S.Ct. 1889, 1902, 64 L.Ed.2d 525 (1980) (Rehnquist, J., dissenting), *cited with approval in Chisom* v. *Roemer*, 501 U.S. 380, 396 n. 23, 111 S.Ct. 2354, 2364 n. 23, 115 L.Ed.2d 348 (1991)).

Finally, the commenter asserts that EPA's interpretation of the CAA to allow a SIP call in the absence of a transport commission recommendation reads out of the CAA the consensual transport commission procedures under sections 176A and 184. This is simply not true. The EPA interprets the transport commission process to be one tool to assess and address interstate transport. In fact, the Northeast Ozone Transport Commission, under section 184, has been active since enactment of the 1990 Amendments. In 1995, EPA approved a recommendation of that commission (60 FR 4712 [14]). Transport commissions remain a viable means for dealing with interstate transport. Furthermore, contrary to the general implication of the commenter's remark, the OTAG process, though not a formal transport commission, provided an opportunity not only for Federal and State governments to assess jointly the transport issue, but also involved industry, environmental groups and others. The EPA based its SIP call on information developed through OTAG, as well as additional analyses performed by the Agency and information submitted by a variety of groups during the comment period on the proposed rule. Thus, the OTAG process contained consensual elements.

(2) Commenters' Arguments Concerning the Virginia case. Under one of the approaches described in the proposed rule, EPA proposed to determine, for each of various upwind States, the aggregate ''amounts'' of air pollutants (NO_X) that contribute significantly to nonattainment, and that, therefore must be prohibited by the various SIPs. The NO_X emissions budget for each State is an expression of the amount of NO_X emissions that would remain after the State prohibits the amount that contributes significantly to downwind nonattainment. In the final rule issued today, EPA has continued this approach, establishing emissions budgets for each of the 23 jurisdictions based on required reductions. This determination is an important step toward assuring that overall air quality standards are met downwind.

Commenters argue that even if EPA has authority to call on States to address interstate transport, EPA does not have the authority under section 110(a)(2)(D) to mandate that upwind States limit NO_X emissions to specified amounts. Rather, according to this view, EPA's authority is limited to determining that the upwind States' SIPs are inadequate, and generally requiring the upwind States to submit SIP revisions to correct the inadequacies. The upwind States would then, according to this view, submit a SIP revision that implements what the upwind States determine to be the appropriate amount of NO_X reductions. If EPA believes that those amounts are too small to correct the inadequacy, EPA could disapprove the SIP revisions.

Proponents of this view rely on the recent decision in *Virginia* v. *EPA,* 108 F.3d 1397, 1406–10 (D.C. Cir. 1997) (*Virginia*) (citing *Train* v. *NRDC*), in which the court vacated EPA's SIP call on the basis that through it, EPA gave States no choice but to adopt the California low emission vehicle (LEV) program. The court found that the language in section 110(k)(5) that provides EPA with the authority to call on a State to revise its SIP ''as necessary'' to correct a substantial inadequacy did not change the longstanding precept that States have the primary authority for determining the mix of control measures needed to attain the NAAQS.

The EPA disagrees that the CAA prohibits EPA from establishing an emissions budget through a SIP call requiring upwind States to prohibit emissions that contribute significantly to downwind nonattainment. Section

[14] In *Commonwealth of Virginia* v. *EPA* , 108 F.3d 1397 (D.C. Cir. 1997), the court vacated EPA's SIP call in response to the Northeast Ozone Transport Commission's recommendation on the basis that the EPA could not require States to adopt a specific control measure under its section 110(k)(5) authority and that, in any event, EPA could not require States to adopt stricter motor vehicle emission standards under either section 110(k)(5) or section 184.

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110(a)(2)(D) is silent regarding whether States or EPA are to determine the level of emission reductions necessary to mitigate significant contribution. The caselaw cited by the commenters only provides that States are primarily responsible for determining the mix of control measures—not the aggregate emission reduction levels that are necessary. Moreover, *Train* v. *NRDC*, which underlies the *Virginia* court's decision, relied on section 107(a) of the CAA, which specifies only that each State is primarily responsible for determining a control strategy to attain the NAAQS ''within such State.''

Section 110(a)(2)(D) does not provide who—EPA or the States—is to determine the level of emission reductions necessary to address interstate transport. As quoted above, section 110(a)(2)(D)(i)(I) requires that SIPs contain ''adequate provisions prohibiting * * * [sources] from emitting any air pollutant in amounts which will contribute significantly to nonattainment'' downwind. Nor does this provision indicate the criteria for determining the ''amounts'' of pollutants that contribute significantly to nonattainment downwind. Nor does this provision indicate the process for determining those ''amounts,'' including whether EPA or the States should carry out this responsibility. [15] Under *Chevron U.S. A., Inc.* v. *Natural Resources Defense Council* , 468 U.S. 1227, 105 S.Ct. 28, 82 L.Ed.2d 921 (1984) (*Chevron*), because the statute does not answer these specific issues, EPA has discretion to provide a reasonable interpretation.

Neither the decision in *Virginia*, nor the body of caselaw upon which it relies, addresses this issue. Rather, these cases address solely the division between the States and EPA regarding the initial identification of control measures necessary to attain the ambient air quality standards. The issue before the court in Virginia was whether EPA had offered States a choice in selecting control measures or instead had mandated the adoption of a specific control measure. Relying on *Train* v. *NRDC*, 421 U.S. 60, 95 S.Ct. 1470, 43 L.Ed.2d 731 1975), the *Virginia* court found that under title I of the CAA, EPA is required to establish the overall air quality standards, but the States are primarily responsible for determining the mix of control measures needed to meet those standards and the sources that must implement controls, as well as the applicable level of control for those sources. The EPA must then review the State's determination only to the extent of assuring that the overall air quality standards are met. If EPA determines that the SIP's mix of control measures does not result in achieving the overall air quality standards, EPA is required to disapprove the SIP and promulgate a FIP, under which EPA selects the sources for emissions reductions (*Virginia*, 108 F.3d at 1407–08, *citing Train* v. *NRDC,* 421 U.S. 60, 95 S.Ct. 1470, 43 L.Ed.2d 731 (1975); *Union Electric Co.* v. *EPA,* 427 U.S. 246, 96 S.Ct. 2518, 49 L.Ed.2d 474 (1976)). This line of cases, which focuses on the selection of controls, does not address whether EPA or the States—in the first instance—should determine the aggregate amount of reductions necessary to address interstate transport.

Moreover, *NRDC* v. *Train* addresses State plans for purposes of intrastate emissions planning. In determining that States have the primary authority for determining the control measures needed to attain the standard, the court relied on section 107(a) of the CAA, which provided (and still provides) that:

> Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality region in such State.''

(421 U.S. at 64, 95 S.Ct at 1474–75 (emphasis added)).

Thus, the underlying support for the court's determination in *Train* v. *NRDC* applies only where a State is determining the mix of controls within its boundaries, not to the broader task of determining the aggregate emissions reductions needed in conjunction with emissions reductions from a number of other States in order to address the impact of transported pollution on downwind States. [16]

Although the cases to date have not addressed directly whether it is the province of EPA or the States to determine the aggregate amounts of emissions to be prohibited (and hence, the amounts that may remain—i.e., the emissions budgets), EPA believes it reasonable to interpret the ambiguity in section 110(a)(2)(D)(i)(I) to include this determination among EPA's responsibilities, particularly in the current circumstances. Determining the overall level of air pollutants allowed to be emitted in a State is comparable to determining overall standards of air quality, which the courts have recognized as EPA's responsibility, and is distinguishable from determining the particular mix of controls among individual sources to attain those standards, which the caselaw identifies as a State responsibility. In *Train*, a State was required to assure that its own air quality attained overall air quality standards and to implement emissions controls to do so. Under these circumstances, the court clarified that while the responsibility for determining the overall air quality standards was EPA's, the responsibility for determining the specific mix of controls designed to achieve that air quality was the State's. By comparison, as stated earlier, a transport case, under section 110(a)(2)(D)(i), does not concern any requirement of the upwind State to assure that its own air quality attains overall air quality standards. Rather, a transport case concerns the upwind State's requirement to assure that its emissions are reduced to a level that will not contribute significantly to nonattainment downwind. Determining this overall level of reductions for the upwind State is analogous to determining overall air quality standards, and, thus, should be the responsibility of EPA.

Once EPA determines the overall level of reductions (by assigning the aggregate amounts of emissions that must be eliminated to meet the requirements of section 110(a)(2)(D)), it falls to the State to determine the appropriate mix of controls to achieve those reductions. Unlike the regulation at issue in *Virginia*, today's regulation establishing emission budgets for the States does not limit the States to one set of emission controls. Rather, the States will have significant discretion to choose the appropriate mix of controls to meet the emissions budget. The EPA has based the aggregate amounts to be prohibited on the availability of a subset of cost-effective controls that are among the most cost effective available. As explained elsewhere in this final rule and the NPR, the State may choose from a broader menu of cost-effective, reasonable alternatives, including some (e.g., vehicle inspection and maintenance programs and reformulated

[15] The EPA is not contending that the ''as necessary'' language in section 110(k)(5) provides the basis for EPA's authority to identify the emissions budget for upwind States.

[16] The court's decision in *Train* v. *NRDC* appears to rely on the plain language of the statute in holding that a State is primarily responsible for determining the mix of control measures necessary to demonstrate attainment within that State's borders. The court in *Virginia* appears to adopt this ''plain meaning'' interpretation without addressing that the language in section 107(a) applies only to intrastate issues. This issue is not relevant in the present case, however, since States are free to decide the mix of control measures under today's final action.

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gasoline) that may even be more advantageous in light of local concerns.

The task of determining the reductions necessary to meet section 110(a)(2)(D) involves allocating the use of the downwind States' air basin. This area is a commons in the sense that the contributing State or States have a greater interest in protecting their local interests than in protecting an area in a downwind State over which they do not have jurisdiction and for which they are not politically accountable. Thus, in general, it is reasonable to assume that EPA may be in a better position to determine the appropriate goal, or budget, for the contributing States, while leaving to the contributing States' discretion to determine the mix of controls to make the necessary reductions.

The EPA's decision to assign the budgets in the final rule is particularly reasonable. Today's rulemaking involves almost half the States in the Nation, and although these States participated in OTAG beginning more than 3 years ago, they still have not agreed on whether particular upwind States should be treated as having sources whose emissions contribute significantly to downwind nonattainment, what the aggregate level of emissions reductions should be, or what the State-by-State reductions should be. The sharply divergent positions taken by the States in their comments on the NPR and SNPR raise doubts that those disagreements could ever be resolved by consensus. It is most efficient—indeed necessary—for the Federal government to establish the overall emissions levels for the various States. This is particularly true for an interstate pollution problem such as the one being dealt with in this action where the downwind areas at issue are affected by pollution coming from several States and the actions taken by each of the concerned States could have an effect on the appropriate action to be taken by another State. For example, if EPA did not specify the emissions to be prohibited from each of the various States affecting New York City, each of those States might claim it could reduce its emissions less provided other States did more. Or, a State close to New York might assert that it could just as effectively deal with its contribution to New York through additional VOC, rather than NO_X, reductions and submit a section 110(a)(2)(D) SIP based on a VOC-control rather than NO_X-control strategy. These choices, however, even assuming they were valid, necessarily relate to the choices that would need to be made by the other upwind States (e.g., Pennsylvania's choice of a VOC-dominated 110(a)(2)(D) control strategy to deal with its contribution to New York could affect what Ohio or New Jersey would need to do to deal with their own contributions by lowering the overall level of NO_X reductions being obtained throughout the pertinent region). Where many States are involved and the choices of each individual State could affect the choices and decisions of the other States the need for initial federal action is manifest. The EPA's action to determine the amount of NO_X emissions that each of the States must prohibit in this widespread geographic area is needed to enable the States to decide expeditiously how to achieve those reductions in an efficient manner that will not undermine the actions of another State. By notifying each State in advance of its reduction requirements, EPA enables each State to develop its plan with full knowledge of the amount and kind of reductions that must be achieved both by itself and other affected States. The EPA's action provides the minimum framework necessary for a multi-state solution to a multi-state problem while preserving the maximum amount of state flexibility in terms of the specific control measures to be adopted to achieve the needed emission reductions. The reasonableness of EPA's approach to the interstate ozone transport problem was recently recognized by a US Court of Appeals in the context of upholding EPA's redesignation of the Cleveland ozone nonattainment area to attainment in light of EPA's approach to the regional transport problem. In the course of doing so the court rejected the contention that a separate analysis of the current adequacy of the Cleveland SIP under section 110(a)(2)(D) was required as a prerequisite to redesignation. The court, after describing the November 7, 1997 proposed SIP call and the path EPA was on to deal with this multi-state regional problem, upheld EPA's redesignation and stated that ''[w]e find that the EPA's approach to the regional transport problem is reasonable and not arbitrary or capricious.'' *Southwestern Pennsylvania Growth Alliance* v. *Browner,* 144 F.3d 984, 990 (6th Cir. 1998).

As noted above, commenters have argued that if EPA determines to issue any SIP call, the SIP call must be more general (i.e., one that simply requires revised SIPs from upwind areas) and not specify the amounts of NO_X emissions that those areas must prohibit. However, if EPA issued a general SIP call and an upwind State responded by submitting an inadequate SIP revision, EPA would disapprove that SIP, and in the disapproval rulemaking, EPA would be obliged to justify why the submitted SIP was unacceptable. Without determining an acceptable level of NO_X reductions, the upwind State would not have guidance as to what is an acceptable submission. The EPA's determination, as part of the issuance of the SIP call, of the amounts of NO_X emissions the SIPs must prohibit obviously provides for more efficient and smooth-running administrative processes at both the State and Federal levels. For the same reasons that EPA believes it is appropriate for the Agency to establish the emissions budgets under the authority of section 110(a)(2)(D) and (k)(5), EPA believes that it is necessary to do so through a rule under the general rulemaking authority of section 301(a). Setting such a rule is necessary, as a practical matter, for the Administrator's effective implementation of section 110(a)(2)(D). *See NRDC* v. *EPA,* 22 F.3d 1125, 1146–48. Without such a rule the States could be expected to submit SIPs reflecting their conflicting interests, which could result in up to 23 separate SIP disapproval rulemakings in which EPA would need to define the requirements that each of those States would need to meet in their later, corrective SIPs. That in turn would trigger a new round of SIP rulemakings to judge those corrective SIPs. The delay attendant to that process would thwart timely attainment of the ozone standards.

2. Authority and Process for Requiring SIP Submissions under the 8-Hour Ozone NAAQS

a. Authority for Requiring SIP Submissions under the 8-Hour NAAQS. (1) SIP Submissions Under CAA Section 110(a)(1). In the NPR and SNPR, EPA proposed to require the 23 upwind jurisdictions to submit SIP revisions to reduce emissions that exacerbate ozone problems in downwind States under the 8-hour ozone NAAQS, as well as the 1- hour NAAQS. The EPA recognized that under the 8-hour NAAQS, areas have not yet been designated as attainment, nonattainment, or unclassifiable, and are not yet required to have SIPs in place. Even so, EPA proposed that upwind areas be required to submit SIPs meeting the requirements of section 110(a)(2)(D)(i)(I) with respect to the 8-hour NAAQS.

In today's action, EPA is confirming its view that it has authority under the 8-hour NAAQS to require SIP submittals under section 110(a)(2)(D)(i)(I) to reduce NO_X emissions by the prescribed amounts. Section 110(a)(1) provides, in relevant part—

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Each State shall * * * adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) * * * a plan which provides for implementation, maintenance, and enforcement of such primary standard in each (area) within such State.

Section 110(a)(2) provides, in relevant part—

Each implementation plan submitted by a State under this Act shall be adopted by the State after reasonable notice and public hearing. Each such plan shall [meet certain requirements, including those found in section 110(a)(2)(D)].

The provisions of section 110(a)(1) and (a)(2) apply by their terms to all areas, regardless of whether they have been designated as attainment, nonattainment, or unclassifiable under section 107. The plain meaning of these provisions, read together, is that SIP revisions are required under the revised NAAQS within 3 years of the date of revision, or earlier if EPA so requires, and that those SIP revisions must meet the requirements of section 110(a)(2), including subparagraph (D).

That the SIP submission requirements of section 110(a)(1) are triggered by the promulgation of a new or revised NAAQS is made even clearer by comparing section 172(b), which applies by its terms only to areas that have been designated nonattainment under section 107. Section 172(b) provides, in relevant part—

At the time the Administrator promulgates the designation of any area as nonattainment with respect to a [NAAQS] under section 107(d) * * *, the Administrator shall establish a schedule according to which the State containing such area shall submit a plan or plan revision * * * meeting the applicable requirements of subsection (c) of this section and section 110(a)(2) * * * Such schedule shall at a minimum, include a date or dates, extending no later than 3 years from the date of the nonattainment designation, for the submission of a plan or plan revision * * * meeting the applicable requirements of subsection (c) of this section and section 110(a)(2) * * *

Section 172(b) establishes the schedule for submissions due with respect to nonattainment areas under sections 172(c) and 110(a)(2). The section 172(c) requirements apply only with respect to areas designated nonattainment. [17]

In the NPR, EPA proposed that section 110(a)(1) mandates SIP submissions meeting the requirements of section 110(a)(2)(D) and provides full authority for EPA to establish a submission date within 3 years of the July 18, 1997 8-hour ozone NAAQS promulgation date (62 FR 38856 (NAAQS rulemaking): 62 FR 60325 (NOx SIP call NPR)). The EPA further asserted in the NPR that EPA has the authority to establish different submittal schedules for different parts of the section 110(a)(1) SIP revision, and that EPA may require the section 110(a)(2)(D) submittal first so that upwind reductions may be secured at an earlier stage in the regional SIP planning process (62 FR 60325). Subsections (ii) and (iii) of this section further elaborates on the reasoning underlying EPA's decision to retain its proposal to require SIP submissions under section 110(a)(2)(D) for the 8-hour standard.

(2) Commenters and the Definition of ''Nonattain ment.'' Commenters challenged several aspects of EPA's proposal to evaluate the contribution of upwind areas under the 8-hour NAAQS. Commenters asserted that section 110(a)(2)(D)(i) applies to constrain emissions from upwind sources only with respect to downwind areas that are designated nonattainment. According to these commenters, until EPA designates areas nonattainment under the 8-hour NAAQS, EPA has no authority to require SIP submissions, under section 110(a)(1), from upwind areas with respect to the 8-hour NAAQS. One commenter pointed out that the new source review requirements and ozone nonattainment requirements enacted in the 1990 Amendments apply only to areas designated nonattainment.

The EPA disagrees with this comment. Section 110(a)(2)(D)(i)(I) provides that a SIP must prohibit emissions that ''contribute significantly to nonattainment in * * * any other State.'' [18] The provision does not, by its terms, indicate that this downwind ''nonattainment'' must already have been designated under section 107 as a nonattainment ''area.'' If the provision were to employ the term ''area'' in conjunction with the term ''nonattainment,'' then it would have to be interpreted to apply only to areas designated nonattainment. Other provisions of the CAA do employ the term ''area'' in conjunction with ''nonattainment,'' and these provisions clearly refer to areas designated nonattainment (e.g., sections 107(d)(1)(A)(i), 181(b)(2)(A), 211(k)(10)(D)). Similarly, the provisions to which the commenter appeared to refer—section 172(b)/172(c)(5) (new source review) and section 181(a)(1)/182 (classified ozone nonattainment area requirements)—by their terms apply to a nonattainment ''area.'' In contrast, section 110(a)(2)(D) refers to only ''nonattainment,'' not to a nonattainment ''area.''

By the same token, section 176A(a) authorizes EPA to establish a transport region whenever ''the Administrator has reason to believe that the interstate transport of air pollutants from one or more States contributes significantly to a violation of a [NAAQS] in one or more other States.'' This reference to ''a violation of a [NAAQS]'' makes clear that EPA is authorized to form a transport region when an upwind State contributes significantly to a downwind area with nonattainment air quality, regardless of whether the downwind area is designated nonattainment. The EPA believes that section 110(a)(2)(D) should be read the same way in light of the parallels between section 110(a)(2)(D) and section 176A(a). Both provisions address transport and both are triggered when emissions from an upwind area ''contribute significantly'' downwind. It seems reasonable to apply a consistent approach to the type of affected downwind area, which would mean interpreting the term ''nonattainment'' in section 110(a)(2)(D) as synonymous with the phrase ''a violation of a [NAAQS]'' in section 176A(a). The CAA contains other provisions, as well, that refer to the factual, air quality status of a particular area as opposed to its designation status. These provisions include, among others, (i) sections 172(c)(2) and 171(1), the reasonable further progress requirement, which requires nonattainment SIPs to provide for ''such annual incremental reductions in emissions * * * as * * * may * * * be required * * * for the purpose of ensuring attainment of the [NAAQS]'' (emphasis added); and (ii) section 182(c)(2), the attainment demonstration requirement, which mandates a ''demonstration that the [SIP] * * * will provide for attainment of the [NAAQS]'' (emphasis added). The emphasized terms clearly refer to air quality status. In a series of notices in the **Federal Register** , EPA relied on these references to air quality status in determining that areas seeking to redesignate from nonattainment to attainment did not need to complete ROP SIPs or attainment demonstrations—even though those requirements generally applied to areas

[17] As quoted above, section 172(b) refers to ''applicable requirements of * * * section 110(a)(2).'' This reference appears to mean those requirements of section 110(a)(2) that either (i) relate to all SIP submissions, such as the requirement for reasonable notice and public hearing in the language at the beginning of section 110(a)(2); or (ii) relate particularly to SIP submissions required for nonattainment areas, but that have not yet been submitted by the State.

[18] Section 110(a)(2)(D)(i)(I) further provides that a SIP must prohibit emissions that ''interfere with maintenance by * * * any other State.''

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designated nonattainment—as long as the air quality for those redesignating areas was, in fact, in attainment. See ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Proposed Rule,'' 57 FR 13498, 13564 (April 16, 1992); ''Determination of Attainment of Ozone Standard for Salt Lake and Davis Counties, Utah, and Determination Regarding Applicability of Certain Reasonable Further Progress and Attainment Demonstration Requirements: Direct Final Rule,'' 60 FR 30189, 30190 (June 8, 1995); and ''Determination of Attainment of Ozone Standard for Salt Lake and Davis Counties, Utah, and Determination Regarding Applicability of Certain Reasonable Further Progress and Attainment Demonstration Requirements: Final Rule,'' 60 FR 36723, 36724 (July 18, 1995). The EPA's interpretation was upheld by the Court of Appeals for the 10th Circuit, in *Sierra Club* v. *EPA* , 99 F.3d 1551, 1557 (10th Cir. 1996).

Accordingly, EPA believes it clear that the reference in section 110(a)(2)(D)(i)(I) to ''nonattainment'' refers to air quality, not designation status. The EPA believes this matter is clearly resolved by reference to the terms of the provision itself, so that under the first step of the *Chevron* analysis, no further inquiry is needed. If, however, it were concluded that the provision is ambiguous on this point, then EPA believes that, under the second step in the *Chevron* analysis, EPA should be given deference for any reasonable interpretation. Interpreting ''nonattainment'' to refer to air quality is reasonable for the reasons described above. [19]

The structure of the schedules for requiring SIP submissions and designating areas nonattainment provides support for EPA's interpretation. As noted above, section 110(a)(1) requires States to submit SIPs covering all their areas—regardless of whether designated, or how designated— within 3 years of a NAAQS revision and requires that those SIPs include provisions meeting the requirements of section 110(a)(2)(D). [20] When a new or revised NAAQS is promulgated, section 107(d)(1) authorizes a process of up to 3 years for designations. States must recommend designations within one year of promulgation of a new or revised NAAQS and EPA must designate areas within 2 years of promulgation; EPA may take up to 3 years to designate areas if insufficient information prevents designations within 2 years. In the case of the 8-hour ozone NAAQS, Congress provided specific legislation for designations (Pub. L. 105–178 § 6103). Under this new legislation, States are provided 2 years to make recommendations and EPA must designate areas within 1 year of the time State recommendations are due. Because of this legislation, designations must occur 3 years following promulgation of the NAAQS (July 2000). The EPA believes that it is not sensible to interpret the term ''nonattainment'' in section 110(a)(2)(D)(i)(I) to refer to nonattainment designations because those designations may not be made until 3 years after the promulgation of a new or revised NAAQS, and the section 110(a)(2)(D) submittals are due within 3 years.

Further, interpreting the reference to ''nonattainment'' as a reference to air quality, and not designation, is consistent with the air quality goals of section 110(a)(2)(D) and the CAA as a whole. In the present case, it is clear from air quality monitoring and modeling that large areas of the eastern part of the United States are in violation of the 8-hour NAAQS, and it is also clear from air quality modeling studies that NO_X emissions from sources in upwind States contribute to those air quality violations. The EPA currently has available all the information that it needs to determine whether upwind States should be required to revise their SIPs to implement appropriate reductions in NO_X emissions. The designation process will clarify the precise boundaries of the downwind areas, but because ozone is a regional phenomenon, information as to the precise boundaries of the downwind areas is not necessary to implement the requirements of section 110(a)(2)(D)(i). As a result, no air quality purpose will be served by waiting until the downwind areas are designated nonattainment.

On the contrary, taking action now is necessary to protect public health. As described in Section I.G., the regional NO_X reductions required under today's action will allow numerous areas currently in violation of the 8-hour NAAQS to attain that standard. For the millions of people living in those areas, today's action will advance the date by which these areas will meet the revised ozone standard. Taking action now is particularly important because one of the sub-population groups at higher risk to ozone health effects is children who are active and spend more time outdoors during the summer months when ozone levels are elevated.

(3) EPA's Authority to Require Section 110(a)(2)(D) Submissions in Accordance with section 110(a)(1). Commenters argue that sections 110(a)(1), (a)(2), and 172(b) should be read so that only requirements under section 110(a)(2) that are unrelated to nonattainment are due under the section 110(a)(1) timetable. These commenters contend that requirements under section 110(a)(2) that are related to nonattainment—including section 110(a)(2)(D)—are due under the section 172(b) timetable, that is, within 3 years of the designation of areas as nonattainment. In support, these commenters rely on language in section 110(a)(1) indicating that the submissions are for plans for air quality regions ''within such State.'' Finally, certain commenters cite as further support for their position the definition of the term ''nonattainment'' as found in section 107(d)(1)(A), claiming that the definition includes interstate transport areas.

As noted above, section 110(a)(1) provides that States must submit SIP revisions providing ''for the implementation, maintenance and enforcement'' of the NAAQS in each area of the State within 3 years (or a shorter time prescribed by the Administrator) following promulgation of a new or revised NAAQS. Section 110(a)(2) then sets forth the applicable elements of a SIP. These provisions apply to all areas within the State, regardless of designation. Section 172(b) establishes a SIP submission schedule for nonattainment areas. It provides that at the time EPA designates areas as nonattainment, EPA shall establish a SIP submission schedule for the submission of a SIP meeting the requirements of section 172(c).

While EPA agrees that there is overlap between the submission requirements under sections 110(a)(1)–(2) and 172(c), EPA believes that the plain language of section 110(a)(1)–(2) authorizes EPA to require the section 110(a)(2)(D) SIPs on the schedule described today, and that there is nothing to the contrary in section 172. Sections 110(a)(2) and 172 contain cross-references to each other. [21]

[19] Similarly, EPA believes that the term ''maintenance'' in another clause of section 110(a)(2)(D)(i)(I) refers to air quality status as well. This clause includes only the term ''maintenance,'' and does not include the term ''area.''

[20] See ''Re-issue of the Early Planning Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS),'' memorandum from Sally L. Shaver, dated June 16, 1998.

[21] Section 110(a)(2)(D) provides that areas designated nonattainment must submit SIPs in accordance with ''part D'' (which includes section 172). Section 172(b) requires EPA to establish a schedule for designated nonattainment areas to meet the requirements of sections 172(c) and

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These cross-references indicate that under certain circumstances, the section 110(a)(2)(D) submittal may be required under section 110(a)(1); and under other circumstances, the section 110(a)(2)(D) submittal may be required under section 172(b). These cross-references are particularly relevant with respect to nonattainment areas, which are subject to both sections 110(a) (1) and (2) and 172. In the current situation, EPA believes that it is appropriate to require the submissions to meet section 110(a)(2)(D) in accordance with the schedule in section 110(a)(1) rather than under the schedule for nonattainment areas in section 172(b). [22]

The EPA has provided that, for the revised ozone and particulate matter NAAQS, States must assess their section 110 SIPs by July 18, 2000 to ensure that they adequately provide for implementing the revised standards. See Re-issue of the Early Planning Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS), memorandum from Sally L. Shaver, dated June 16, 1998. The EPA recognized that the section 110 SIP should generally be sufficient to address the revised NAAQS. However, the Agency noted three areas that the States particularly needed to assess, including whether the SIP adequately addressed section 110(a)(2)(D). The EPA also provided that the States should submit revisions to address section 110(a)(2)(D) on the timeframe established by the final NO_X SIP call, when issued. The submittal date that EPA has specified in the final NO_X SIP call rule is consistent with both the Early Planning Guidance and with section 110(a)(1) and (2) of the CAA.

The EPA acknowledges that it has not historically required an affirmative submission under section 110(a)(2)(D), applicable to specific sources of emissions, in response to the promulgation of a new or revised NAAQS. In part, this is because sufficient technical information was not available to determine which sources ''contribute significantly'' to nonattainment in a downwind area. In the absence of such a determination, States were unable to regulate sources under this provision in any meaningful way. However, based on the many analyses performed over the last several years, EPA believes that there is now affirmative information regarding significant contribution to ozone violations in the eastern portion of the country; in light of that evidence, it would not be appropriate to defer action under section 110(a)(2)(D) until a later time.

Moreover, as noted above, the section 172(c) SIP submissions apply only to areas designated nonattainment. Specifically, section 172(b) provides that ''[a]t the time'' EPA designates an area as nonattainment, EPA shall set a schedule ''according to which the State containing such area shall submit'' SIPs. Section 171(2) provides further clarification by providing that for purposes of part D of title I of the CAA (CAA sections 171–193) ''[t]he term 'nonattainment area' means, for any air pollutant, an area which is designated 'nonattainment' with respect to that pollutant within the meaning of section 107(d).'' By its terms then, section 172 does not apply to areas designated attainment or unclassifiable (even if such areas are not attaining the standard) or for areas not yet designated. Thus, section 110(a)(1) provides the only submission schedule for areas not designated nonattainment. For those areas, the commenters' argument that section 172(b) should establish the timetable for section 110(a)(2)(D)(i) SIPs clearly fails. Since certain portions of the 23 jurisdictions covered by this rule likely will not be designated nonattainment for the 8-hour standard, EPA believes that the section 110(a)(1) schedule is the only schedule (and thus is the reasonable schedule) to follow for purposes of the SIP call.

Furthermore, contrary to the commenters' assertions, the definition of nonattainment does not broadly include areas that contribute to nonattainment in a downwind State. The definition of nonattainment includes areas that have monitored violations of the standard and areas that ''contribute to ambient air quality in a nearby area'' that is violating the standard (section 107(d)(1)(A)(i) (emphasis added)). Thus, only ''nearby'' areas that contribute to violations of a standard will be included in the nonattainment designation; areas contributing to longer-range transport will not be designated nonattainment based solely on that longer-range transport. Therefore, they will not be subject to section 172(c) requirements and timing.

The commenters argue that EPA's position that section 110(a)(1) governs the section 110(a)(2)(D) SIP submittal schedule leads to the absurd result that upwind areas will be required to submit SIPs dealing with their contribution to a nonattainment problem downwind before the downwind area will be required to submit SIPs under section 172(b). The commenters explain that section 110(a)(2) requires SIP submittals on a faster timetable (within 3 years from the date of promulgation or revision of a NAAQS) than section 172(b) (within 3 years from the date of designation as nonattainment). The commenters also contend that section 107 provides that States have the primary responsibility for ensuring attainment within their boundaries; only after a State implements all statutorily required and necessary measures can it pursue reductions in other areas through a SIP call or section 126. The commenters contend that the SIP call is contrary to the plain language of section 107 and congressional intent because it would require upwind areas to implement controls before the downwind area has implemented all statutorily required or necessary controls.

While it is true that plans to meet the emissions budget for the SIP call will be due prior to nonattainment designations and attainment plans for areas designated nonattainment for the 8-hour standard, EPA does not consider this result to be absurd in the present case.

The CAA, at least since its amendment in 1970, has required States to regulate ozone. For more than the past 25 years, States have focused on the adoption and implementation of local controls for the purpose of bringing nonattainment areas into attainment. Thus, historically, the downwind nonattainment areas have borne the brunt of the control obligations through the implementation of local controls. In comparison, areas in attainment of the NAAQS, but upwind of nonattainment areas, have not been required to implement controls designed to ameliorate the air quality problems experienced by their downwind neighbors.

Since the CAA Amendment of 1977, designated nonattainment areas have been subject to specific local control obligations, such as vehicle I/M and, for stationary sources, the requirement to implement RACT. The CAA Amendments of 1990 tightened these control obligations for many areas. Moderate, serious, severe and extreme areas were required to reduce emissions by 15 percent between 1990 and 1996. In addition, each serious, severe and extreme area is required to achieve 9 percent reductions over the succeeding 3 year periods until the area attains the

110(a)(2); section 172(c)(7) requires that nonattainment SIPs shall meet the requirements of section 110(a)(2).

[22] In other situations, EPA has indicated that certain elements of section 110(a)(2) would be better addressed in accordance with the timeframe established in section 172. See e.g., 60 FR 12492, 12505 (March 7, 1995) Proposed Requirements for Implementation Plans and Ambient Air Quality Surveillance for Sulfur Oxides (Sulfur Dioxide) National Ambient Air Quality Standard.

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standard. Additional requirements, such as the use of RFG and the use of vapor recovery devices on gasoline pumps, are also required for certain areas (see generally, CAA section 182 and, e.g., section 211(k)). Thus, downwind areas with nonattainment problems under the 1-hour NAAQS are under current obligations to submit SIP revisions containing local control measures for that standard. For these areas, local reductions needed to meet the 1-hour standard are already occurring and will be achieved prior to or on the same schedule as reductions States may require in response to the SIP call.

Furthermore, in many of the downwind areas, States have been taking action to reduce ozone levels for many years in order to meet the 1-hour ozone NAAQS. Although the fact that the 8-hour ozone NAAQS is a new form of the ozone standard, however, should not obscure the fact that the downwind States have been making efforts to reduce ozone levels for decades. The EPA believes that the history of implementation by downwind areas of ozone pollution controls further mitigates the commenters' argument that it is absurd to require upwind areas to implement controls in advance of downwind attainment demonstrations under the 8-hour NAAQS.[23]

Moreover, virtually all of the downwind States affected by today's rulemaking, due to 8-hour ozone nonattainment or maintenance problems, are themselves upwind contributors to problems further downwind, and, thus, are subject to the same requirements as the States further upwind.[24] The reductions these downwind States must implement due to their additional role as upwind States will help reduce their own 8-hour ozone problems on the same schedule as emissions reductions for the upwind States. Accordingly, for the most part, this rulemaking does not require upwind areas to take action in advance of any action by downwind areas to ameliorate the downwind problems.

Finally, even if EPA were requiring upwind States to take action to reduce downwind nonattainment and maintenance in advance of action by the downwind States, this would simply require upwind areas to take the first step by developing SIPs to eliminate their significant contribution to the downwind problem. The downwind areas will be required to take the next step by developing SIPs that address their share. Generally, an agency may resolve a problem (in this case, downwind nonattainment) on a step-by- step basis (see e.g., *Group Against Smog and Pollution, Inc.* v. *EPA* , 665 F.2d 1284, 1291–92 (D.C. Cir. 1981)).

A commenter has observed that under section 110(a)(1), EPA may authorize section 110(a)(2) submittals as late as 3 years after revision of a NAAQS, which, in this case, would run until July 2000. The Early Planning Guidance, described above, indicates that States are allowed until July 2000 to make submissions concerning other elements of section 110(a)(2). However, as described elsewhere, EPA has determined that the section 110(a)(2)(D) submittals should be submitted by the end of September 1999 to assure that the required NO_X reductions will be implemented as expeditiously as practicable, which EPA has determined is no later than the May 1 start of the 2003 ozone season (see Section V, below).

Citing section 107(a) of the CAA, the commenters assert that the CAA requires downwind areas to fully adopt and implement all statutorily required or necessary measures before EPA can require upwind areas to control emissions. Section 107 provides that States shall have the primary responsibility for assuring air quality within the State by submitting a plan that specifies how the NAAQS will be achieved and maintained in the State. The commenters attempt to read this statement regarding a State's authority to choose the mix of control measures within State boundaries as barring the control of emissions from upwind States.

This provision may be read as focusing on the State-Federal balance in controlling criteria pollutants, such as ozone, not any upwind-State, downwind-State balance. The provision indicates that although EPA may promulgate Federal measures that provide reductions to help States reach attainment, States bear the ultimate responsibility for assuring attainment. Further, this provision may be read to indicate that States may choose the mix of controls to reach attainment within their own boundaries. Nothing in this provision purports to address the need for upwind controls. By comparison, section 110(a)(2)(D) affirmatively requires States to submit a SIP prohibiting emissions that significantly contribute to downwind nonattainment or interfere with maintenance of the NAAQS. Thus, the statute, read as a whole, contemplates that interstate transport will be addressed as part of the downwind States' attainment responsibilities. Indeed, determining the upwind area's share of the problem is necessary in order for downwind attainment planning. In the absence of the upwind reductions that will be achieved, the downwind area would be required to submit an attainment plan to demonstrate attainment regardless of cost and without benefit of the reduction of upwind emissions that significantly contribute to nonattainment. In light of the statute as a whole, it is absurd to argue that Congress intended downwind areas to reduce emissions at any cost while upwind sources that significantly contribute to that nonattainment remain unregulated. Congress attempted to balance responsibilities, providing that States could choose the mix of controls within the State's borders (CAA section 107(a)) and are ultimately responsible for assuring attainment, but also recognizing that emissions reductions from upwind States may be needed for attainment (CAA section 110(a)(2)(D)(i)).

b. Process for Requiring SIP Submissions under the 8-Hour Standard. The time by which the section 110(a)(2)(D) SIP revision under the 8-hour NAAQS must be submitted is governed by section 110(a)(1), which requires the SIP revision to be ''adopt[ed] and submit[ed] to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a [NAAQS] (or any revision thereof) . . . .'' In the NPR, EPA indicated that the SIP revision would be due by the end of September 1999, which EPA expected to be 12 months from the date of completing today's final rule. In today's action, EPA is confirming that the SIP revision will be due September 30, 1999, for the reasons described below in Section VI.A.1, Schedule for SIP Revision.

3. Requirements of Section 110(a)(2)(D)

a. Summary. Today's action is driven by the requirements of CAA section 110(a)(2)(D). This provides that each SIP must—

[23] Although the SIP call will provide a benefit to a wide number of areas, the focus of the SIP call is to reduce boundary conditions for a number of areas that will have difficulty attaining either the 1-hour or 8-hour standard (or both) without the benefit of reductions from outside the nonattainment area. Based on current monitoring data and modeling, EPA predicts that there will be a number of areas that are meeting the 1-hour standard that will be designated nonattainment for the 8-hour standard. The EPA further predicts that many of these areas will come back into attainment due solely to the emission reductions achieved by the NO_X SIP call. However, this incidental benefit—which likely will occur without the need for local emission reductions—does not preclude EPA from requiring the SIP call reductions, which are needed to help other more seriously polluted areas that have long-standing pollution problems.

[24] Maine, New Hampshire, and Vermont are the only downwind States that are not subject to today's action.

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* * * contain adequate provisions—(I) prohibiting, consistent with the provisions of this title, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard * * *

According to section 110(a)(2)(D), the SIP for each area, regardless of its designation as nonattainment or attainment (including unclassifiable), must prohibit sources within the area from emitting air pollutants in amounts that will ''contribute significantly'' to ''nonattainment'' in a downwind State, or that ''interfere with maintenance'' in a downwind State.

b. Determination of Meaning of ''Nonattain ment'' (1) Geographic Scope. In determining the meaning and scope of section 110(a)(2)(D), it is useful first to determine the geographic scope of ''nonattainment'' downwind.

At proposal, EPA stated that it—

* * * proposes to interpret this term to refer to air quality and not to be limited to currently-designated nonattainment areas. Section 110(a)(2)(D) does not refer to ''nonattainment areas,'' which is a phrase that EPA interprets to refer to areas that are designated nonattainment under * * * section 107(d)(1)(A)(I) * * * . Rather, the provision includes only the term 'nonattainment' and does not define that term. Under these circumstances, EPA has discretion to give the term a reasonable definition, and EPA proposes to define it to include areas whose air quality currently violates the NAAQS, and will likely continue [to violate in the future], regardless of the designation of those areas * * *

(62 FR 60324).

To determine whether areas would continue to violate in the future, EPA proposed to take into account the reductions that would result from current CAA control requirements (apart from controls that may be required under section 110(a)(2)(D)). To take these reductions into account, EPA determined whether the area would be in nonattainment in the future based on air quality modeling that assumed CAA-mandated reductions and that accounted for growth. If an area would reach attainment based on required controls, EPA would not view that area as having a nonattainment problem to which any upwind areas may be considered to contribute.

As explained earlier, in today's action, EPA has determined that for purposes of the 8-hour NAAQS, the reference to ''nonattainment'' should be defined as EPA proposed. Thus, in determining whether an upwind area contributes significantly to ''nonattainment'' downwind, EPA would evaluate downwind areas for which monitors indicate current nonattainment, and air quality models indicate future nonattainment, taking into account CAA control requirements and growth.

For the 1-hour standard, EPA proposed to define nonattainment to include all grid cells within a county when a monitor in that county indicated nonattainment. Upon further study, EPA found that in some instances, a metropolitan area may consist of numerous counties, only a few of which contain monitors indicating nonattainment. The EPA recognizes that under the 1-hour NAAQS, nonattainment boundaries are generally used to describe the area with the nonattainment problem; accordingly, EPA believes that this geographic vicinity offers an appropriate indication of an area that may be expected to have nonattainment air quality. The EPA predicts that many 1-hour nonattainment areas that currently monitor nonattainment somewhere within the area will remain in nonattainment in 2007, in some cases because of predicted violations in counties that currently monitor attainment. The EPA believes that the entire area should be considered to be in nonattainment until all monitors in the area indicate attainment of the NAAQS. Thus, in today's action, EPA used the designated nonattainment area in determining the downwind nonattainment problem.[25]

As noted above, commenters disagreed with EPA's view that the term ''nonattainment'' covers areas with air quality that is currently in nonattainment, regardless of designation. The EPA's response to those comments is also set forth above.

(2) 2007 Projection Year. In the NPR, EPA indicated that it would adopt the year 2007 as the year for determining whether areas achieved their required NO_X budget levels. Accordingly, in determining whether downwind areas should be considered to be, and remain in, ''nonattainment,'' EPA would model their air quality in 2007, based on the implementation of CAA required controls by that date, and growth in emissions—generally due to economic growth and greater use of vehicles—by that date. At proposal, EPA adopted this same approach with respect to both the 1-hour and the 8-hour NAAQS (62 FR 60325). The EPA is continuing this approach.

c. Definition of Significant Contribution. As indicated in the NPR, neither the CAA nor its legislative history provides meaningful guidance for interpreting the term ''contribute significantly'' under section 110(a)(2)(D)(i)(I).

(1) ''Contribute.'' The initial step in defining the ''contribute significantly'' term is to determine the meaning of the term ''contribute.'' In the NPR, EPA stated that it believes this term should be defined broadly, so that emissions ''contribute'' to nonattainment downwind if they have an impact on nonattainment downwind (62 FR 60325). Air quality modeling indicated that emissions from the upwind States clearly impact downwind nonattainment problems; as a result, EPA generally folded this step of determining whether sources ''contribute'' to nonattainment downwind into the step of determining whether that contribution is ''significant,'' discussed below.

In addition, section 110(a)(2)(D)(i)(I) requires the SIP to prohibit amounts of emissions ''which *will* contribute significantly * * *'' (emphasis added). The EPA believes that the term ''will'' means that SIPs are required to eliminate the appropriate amounts of emissions that presently, or that are expected in the future, contribute significantly to nonattainment downwind.

Because ozone is a secondary pollutant formed as a result of complex chemical reactions involving numerous sources, it is not possible to determine the downwind impact on each individual source. In addition, ozone generally results from the contributions of numerous sources. As indicated in the NPR:

[U]nhealthful levels of ozone result from emissions of NO_X and VOCs from thousands of stationary sources and millions of mobile sources [and consumer products and other sources] across a broad geographic area. Each source's contribution is a small percentage of the overall problem; indeed, it is rare for emissions from even the largest single sources to exceed one percent of the inventory of ozone precursors even for a single metropolitan area. Under these circumstances, even complete elimination of any given source's emissions may well have no measurable impact in ameliorating the nonattainment problem. Rather, attainment requires controls on numerous sources across a broad area. Ozone is a regional scale

[25] It should be reiterated that EPA relied on the designated area solely as a proxy to determine which areas have air quality in nonattainment. This proxy is readily available under the 1-hour NAAQS because areas have long been designated nonattainment. The EPA's reliance on designated nonattainment areas for purposes of the 1-hour NAAQS does not indicate that the reference in section 110(a)(2)(D)(i)(I) to ''nonattainment'' should be interpreted to refer to areas designated nonattainment.

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problem that requires regional scale reductions

(62 FR 60326).

Accordingly, EPA has adopted a ''collective contribution'' approach to determining whether sources ''contribute'' to nonattainment downwind: EPA determines the impact downwind of emissions in the aggregate from a particular geographic region. If the aggregated emissions are considered to contribute to nonattainment downwind, then all of the emissions in that region should be considered as contributors to that nonattainment problem. In today's action, EPA is continuing the same interpretation of the term ''contribute,'' for the reasons just described.

(2) ''Significantly''. (a) Notice of Proposed Rulemaking. In the NPR, EPA proposed a ''weight-of-evidence,'' or multi-factor, approach for determining whether a contribution is ''significant.''

The EPA proposed two separate interpretations for the term ''contribute significantly,'' which had implications as to which factors were to be considered in what parts of the analysis. Under the first interpretation, significant contribution is determined with reference to—

> * * * factors concerning amounts of emissions and their ambient impact, including the nature of how the pollutant is formed, the level of emissions and emissions density (defined as amount of emissions per square mile) in the particular upwind area, the level of emissions in other upwind areas, the amount of contribution to ozone in the downwind area from the upwind areas, and the distance between the upwind sources and the downwind nonattainment problem. Under this approach, when emissions and ambient impact reach a certain level, as assessed by reference to the factors identified above, those emissions would be considered to ''contribute significantly'' to nonattainment.

(62 FR 60325).

Under this interpretation, after identifying amounts of emissions that constitute a significant contribution, EPA then determines the amount of emissions reductions necessary to adequately mitigate these contributions. This determination entails—

> * * * [e]valuation of the costs of available measures for reducing upwind emissions * * * as well as to the extent known (at least qualitatively), the relative costs of, amounts of reductions from, and ambient impact of measures available in the downwind areas.

Id.

Under the second interpretation, EPA considers all of the factors under both the significant contribution prong and the mitigation prong of the first interpretation, and, once EPA determines an amount of emissions that does significantly contribute to downwind nonattainment, then EPA would determine that the SIP must contain provisions adequate to prohibit that amount of emissions. Id. at 60325– 26.

(b) Today's Action. The EPA has determined that the second interpretation should be used; that is, that the determination of significant contribution includes both air quality factors relating to amounts of upwind emissions and their ambient impact downwind, as well as cost factors relating to the costs of the upwind emissions reductions. Once an amount of emissions is identified in an upwind State that contributes significantly to a nonattainment problem downwind, or interferes with maintenance downwind, the SIP must include provisions to eliminate that amount of emissions.

To reiterate, section 110(a)(2)(D)(i)(I) provides that the SIP must ''prohibit[]'' sources from ''emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other State.'' The term ''prohibit'' is defined as ''to forbid by authority'' or ''prevent,'' or ''preclude.'' ''The American Heritage Dictionary of the English Language'' (3d ed. 1992, 1448). The EPA believes that the term ''prohibit'' means that SIPs must eliminate those amounts of emissions determined to contribute significantly to nonattainment or interfere with maintenance downwind. Moreover, EPA believes that whether emissions ''contribute significantly'' depends on a multifactor test, as described below. Thus, section 110(a)(2)(D)(i)(I) does not require the elimination of all upwind source emissions that impact downwind air quality problems, but only those amounts of emissions that, based on a multi-factor test, significantly contribute to downwind air quality problems.

d. Multi-factor Test for Determining Significant Contribution. In the NPR, EPA proposed a multi-factor test for determining whether emissions from an upwind State contribute significantly to a nonattainment or maintenance problem downwind. The EPA received numerous comments on the factors. Based on the comments and EPA's further analysis, EPA, in today's action, is continuing the multi-factor approach, with some refinements in response to comments, with respect to the factors EPA considered and the manner in which EPA considered them.

In determining whether emissions from upwind States affected by today's action contribute significantly to downwind nonattainment or maintenance problems, EPA specifically considered the following factors with respect to each such upwind State. These factors were the primary components in EPA's consideration.

fl The overall nature of the ozone problem (i.e., ''collective contribution'')

fl The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas

fl The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems

fl The availability of highly cost effective control measures for upwind emissions.

The first three of these factors are related to air quality; the fourth is related to costs.

In addition, EPA generally reviewed several other considerations before concluding that upwind emissions contribute significantly to downwind nonattainment. The EPA did not consider it necessary, or did not have adequate information, to apply each of these factors with specificity with respect to each upwind State's emissions. In addition, in some instances, EPA did not have quantitative information to assess certain of these factors, and instead relied on qualitative information. These considerations were secondary aspects of EPA's analysis. They include:

fl The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems

fl The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas

fl General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls

All of these factors and considerations are described in the following sections.

e. Air Quality Factors. As noted above, EPA specifically considered three air quality factors with respect to each upwind State, which factors, in conjunction with the cost factor discussed in the next section, were the primary components in EPA's consideration:

fl The overall nature of the ozone problem (*i.e.,* ''collective contribution'')

fl The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas

f1 The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems

(1) Collective Contribution. As indicated elsewhere, ozone generally results from the collective contribution of emissions from numerous sources over a large geographic area. For example, for urban nonattainment areas under the 1-hour NAAQS, the downwind sources, comprise numerous stationary sources as well as mobile on-road sources, mobile off-road sources, and consumer and commercial products. Further, additional contributions are made by numerous upwind States, both adjacent to and further away from the nonattainment area itself. The fact that virtually every nonattainment problem is caused by numerous sources over a wide geographic area is a factor suggesting that the solution to the problem is the implementation over a wide area of controls on many sources, each of which may have a small or unmeasureable ambient impact by itself.

(2) Extent of Downwind Nonattainment Problems, Including Ambient Impact of Required Controls. In determining whether a downwind area has a nonattainment problem under the 1-hour standard to which an upwind area may be determined to be a significant contributor, EPA determined whether the downwind area currently has a nonattainment problem, and whether that area area would continue to have a nonattainment problem as of the year 2007 assuming that in that area, all controls specifically required under the CAA were implemented, and all required or otherwise expected Federal measures were implemented. If, following implementation of such required CAA controls and Federal measures, the downwind area would remain in nonattainment, then EPA considered that area as having a nonattainment problem to which upwind areas may be determined to be significant contributors.

Thus, this analytical approach assumes that downwind areas implement all required controls and receive the benefit of reductions from Federal measures, and yet have a residual nonattainment problem (prior to the implementation of the regional reductions required by today's action). The fact that a nonattainment problem persists, notwithstanding fulfillment of CAA requirements by the downwind sources, is a factor suggesting that it is reasonable for the upwind sources to be part of the solution to the ongoing nonattainment problem.

The EPA undertook a comparable analysis with respect to the 8-hour NAAQS. That is, the major urban areas in the northeast, midwest, and south that are violating the 8-hour NAAQS are designated nonattainment under the 1- hour NAAQS as well. After these areas are designated nonattainment under the 8-hour NAAQS, they will become subject to the control requirements of section 172(c). However, for these areas, the section 172(c) requirements do not, by their terms, impose any specific controls other than what these areas have already implemented to fulfill the requirements under section 182 attendant to their designation and classification under the 1-hour NAAQS. Accordingly, the same air quality modeling analyses that shows residual nonattainment for at least one of the urban areas linked to each upwind State under the 1-hour standard shows residual nonattainment for those areas under the 8-hour NAAQS. Indeed, modeling analyses relied on for today's action indicate residual nonattainment for the major urban areas even after the implementation of regional reductions comparable to those required today. [26]

(3) Ambient Impact of Emissions from the Upwind Sources. In today's action, EPA examined the impact of numerous upwind States on numerous downwind areas with nonattainment problems.

Under the 1-hour NAAQS, EPA conducted various air quality modeling analyses that examined the impact of emissions from sources in each upwind State on ozone levels in downwind nonattainment areas, in light of the impact of emissions from sources in other upwind States on the downwind area's nonattainment problem. The EPA assessed the frequency and magnitude of each upwind State's contribution to downwind nonattainment problems. Some of the modeling analyses also permitted determining the magnitude of the average contribution and the peak contribution from each upwind State, as well as the percentage of each upwind State's contribution to the downwind nonattainment problem.

[26] The presence of residual nonattainment in major urban areas after their implementation of specifically required CAA controls supports the regional reductions required under today's action. Those regional reductions allow the major urban areas to progress towards attainment under the 8- hour NAAQS, and, at the same time, significantly ameliorate the nonattainment problems under the 8-hour NAAQS for numerous other areas. In fact, EPA projections indicate that numerous areas with nonattainment problems will achieve attainment of the 8-hour NAAQS as a result of the regional reductions.

The EPA determined that for each upwind State affected by today's action, its contribution to a downwind nonattainment problem, in conjunction with the contribution from other upwind States, comprised a relatively large percentage of the nonattainment problem. The EPA further determined that, in this context, the impacts from each affected upwind State's NO_X emissions are sufficiently large and/or frequent so that the amounts of that State's emissions should be considered to be significant contributions, depending on the cost factor and other relevant considerations. For most upwind States, EPA conducted two types of modeling—UAM–V and CAMx—that isolated the impact of emissions from the upwind State alone on downwind nonattainment.

The EPA also conducted much the same analysis to determine the impact of emissions from each upwind State on ozone levels in downwind States under the 8-hour NAAQS. Because nonattainment problems under the 8-hour NAAQS are widespread, and because EPA has not designated individual nonattainment areas, EPA focused this part of its inquiry on the upwind State's impact on the entire downwind State.

The EPA's analysis under both the 1-hour and 8-hour NAAQS led EPA to conclude that, in light of both the collective contribution nature of the ozone problem, and the fact that downwind areas continue to suffer a nonattainment problem even after implementation of all required CAA measures and Federal measures, emissions from each of the affected upwind States have a sufficiently large and/or frequent ambient impact such that those emissions contribute significantly to nonattainment downwind, depending on the availability of highly cost-effective measures and on other considerations discussed below.

f. Determination of Highly Cost-effective Reductions and of Budgets. After determining the degree to which NO_X emissions, as a whole from the particular upwind States, contribute to downwind nonattainment or maintenance problems, EPA then determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective. By examining the cost effectiveness of recently promulgated or proposed NO_X controls, EPA determined that an average of approximately $2,000 per ton removed

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is highly cost effective. The EPA then determined a set of controls on NO_X sources that would cost no more than an average of $2,000 per ton reduced. Specifically, EPA determined that one set of these controls would include a cap-and-trade program for (i) electricity generating boilers and turbines larger than 25 Mwe (''large EGUs''), and (ii) large non-electricity generating industrial boilers and turbines (''large non-EGU boilers and turbines''). The application of an emission rate of 0.15 lb/mmBtu and 1995–1996 utilization for EGUs and 60 percent for large non-EGUs to the emissions projected to occur in 2007 including growth and CAA measures, led to the determination of the amounts to be reduced. The remaining amount is a State's budget.

The EPA further determined that additional highly cost-effective controls are also available for cement manufacturing sources and internal combustion engines. On the basis of reasonable assumptions concerning growth to the year 2007, EPA then determined the amounts of emissions from these source categories that would be eliminated with those controls.

The EPA further determined that there were no other controls on other NO_X sources that qualify as highly cost effective (although several controls are reasonably cost-effective).

On the basis of the determinations just described for the various source categories, EPA determined an amount of NO_X emissions that may be eliminated through these highly cost-effective measures. Because EPA had also determined that the NO_X emissions from the affected upwind States have a large and/or frequent impact on downwind nonattainment or maintenance problems, EPA concludes that the amount of NO_X emissions from those States that can be eliminated through application of highly cost-effective control measures contributes significantly to nonattainment or maintenance problems downwind.

Under section 110(a)(2)(D)(i)(I), the SIP must include ''adequate provisions prohibiting'' sources from emitting these ''amounts.'' Because no highly cost-effective controls are available to eliminate the remaining amounts of NO_X emissions, EPA concludes that those emissions do not contribute significantly to downwind nonattainment or maintenance problems. As indicated below and in Section III, there are cost-effective alternatives available to States that choose not to adopt all of the highly cost-effective measures on which EPA based its selection of the significant amounts of NO_X emissions.

To implement EPA's determinations, each affected upwind State is required to submit for EPA approval SIP controls projected to be sufficient, by the year 2007, to eliminate the amount of NO_X emissions in the State that EPA determined contributes significantly to nonattainment. The EPA determined this amount of reductions, for each affected upwind State, as follows: EPA first determined the amount of NO_X emissions in that State by the year 2007, based on assumptions concerning both growth and emissions controls that are required under the CAA or that will be implemented due to Federal actions (the ''2007 base case''). Second, EPA applied the control measures identified as highly cost effective to the 2007 base case amount for the appropriate source categories. The amount of NO_X emissions remaining in the State after application of controls to the affected source categories constitutes the 2007 budget. The difference between the 2007 base case and the 2007 budget is the amount of NO_X emissions in that State by the year 2007 that EPA has determined to contribute significantly to nonattainment and that, therefore, the SIPs must prohibit.

The upwind State's SIP revision due in response to today's action must provide controls that, on the basis of the same assumptions (including concerning growth) made by EPA in determining the budget, would limit NO_X emissions in the year 2007 to no more than the 2007 budget. The State has full discretion in selecting the controls, so that it may choose any set of controls that would assure achievement of the budget.

As EPA stated in the NPR:

> States are not constrained to adopt measures that mirror the measures EPA used in calculating the budgets. In fact, EPA believes that many control measures not on the list relied upon to develop EPA's proposed budgets are reasonable—especially those, like enhanced vehicle inspection and maintenance programs, that yield both NO_X and VOC emissions reductions.[27] Thus, one State may choose to primarily achieve emissions reductions from stationary sources while another State may focus emission reductions from the mobile source sector.

(62 FR 60328).

The EPA believes that its overall approach derives further support from the mandate in section 110(a)(2)(D) that each SIP include provisions prohibiting ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts' that adversely affect downwind areas. The phrase ''any source or other type of emissions activity'' may be interpreted to require that the SIP regulate all sources of emissions to assure that the total amount of emissions generated within the State does not adversely affect downwind areas. By its terms, the phrase covers all emitters of any kind because every emitter—stationary, mobile, or area—may be considered a ''source or other type of emissions activity.'' This interpretation is consistent with the legislative history of the phrase. Prior to the CAA Amendments of 1990, the predecessor to section 110(a)(2)(D), which was section 110(a)(2)(E), referred to ''any stationary source within the State.'' In the 1990 Amendments, Congress revised the phrase to read as it currently does. A Committee Report explained, ''Where prohibitions in existing section 110(a)(2)(E) apply only to emissions from a single source, the amendment includes ''any other type of emissions activity,'' which makes the provision effective in prohibiting emissions from, for example, multiple sources, mobile sources, and area sources.'' V Leg. Hist. 8361, S. Rep. No. 228, 101st Cong., 1st Sess. 21 (1989).

For reasons explained below, if an upwind State chooses to achieve all or a portion of the required reductions from large EGUs or large non-EGU boilers and turbines, then the SIP must include a mass emissions limitation for those sources computed with reference to certain growth assumptions and the emission rate limits chosen by the State. The EPA recommends that this mass limitation, or cap, be accompanied by a trading program. Any such cap-and- trade program must be established by May 1, 2003. If the State chooses to achieve all or a portion of the required reductions from other sources, then the State must implement controls, by the year 2003, on those other sources that are projected to achieve the required level of reductions, based on certain assumptions (including growth), in the year 2007. The controls on these other sources may be rate-based, and no emissions cap on them is required. By the year 2007, any applicable mass emissions limitation for large EGUs or large non-EGU boilers and turbines must continue to be met, and any applicable controls on other sources must continue to be implemented. The amount of the 2007 overall budget is used to compute the level of controls that would result in the appropriate amount of emissions reductions, given assumptions concerning, for example,

[27] As indicated in the NPR, EPA considers that measures may be reasonable in light of their reduction of VOC and NO_X emissions, even though their cost-effectiveness in terms of cost per NO_X emissions removed is relatively high (62 FR 60346– 48).

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growth. To this extent, the 2007 overall budget is an important accounting tool. However, the State is not required to demonstrate that it has limited its total NO_X emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.

g. Other Considerations in Determination of Significant Contribution. The EPA reviewed several other considerations in support of its determination that the specified amounts of emissions from the affected upwind States contribute significantly to nonattainment downwind.

(1) Consistency of Regional Reductions with Downwind Attainment Needs. The EPA conducted modeling analyses of emission reductions of virtually the same magnitude as the regional reductions required under today's action. Although the impact on any downwind ozone problem of each upwind State's emissions reductions alone may be relatively small, the impact of those reductions, when combined with the reductions from the other States, is substantial. Based on this modeling, EPA determined that the regional reductions allow downwind nonattainment areas under the 1-hour NAAQS to make appreciable progress towards attainment. The EPA further determined that under the 8-hour NAAQS, many areas with nonattainment problems are expected to reach attainment based solely on the regional reductions, and that other (primarily urban) areas would benefit from the regional reductions but are expected to experience residual nonattainment. EPA further determined that none of the upwind States affected by today's action are affected by ''overkill,'' that is, required reductions that are more than necessary to ameliorate downwind nonattainment in every downwind area affected by that upwind State.

(2) Fairness. The EPA also considered the overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas. Most broadly, EPA believes that overall notions of fairness suggest that upwind sources which contribute significant amounts to the nonattainment problem should implement cost-effective reductions. When upwind emitters exacerbate their downwind neighbors' ozone nonattainment problems, and thereby visit upon their downwind neighbors additional health risks and potential clean-up costs, EPA considers it fair to require the upwind neighbors to reduce at least the portion of their emissions for which highly cost-effective controls are available.

In addition, EPA recognizes that in many instances, areas designated as nonattainment under the 1-hour NAAQS have incurred ozone control costs since the early 1970s. Moreover, virtually all components of their NOx and VOC inventories are subject to SIP-required or Federal controls designed to reduce ozone. Furthermore, these areas have complied with almost all of the specific control requirements under the CAA, and generally are moving towards compliance with their remaining obligations. The CAA's sanctions and FIP provisions provide assurance that these remaining controls will be implemented. By comparison, many upwind States in the midwest and south have had fewer nonattainment problems and have incurred fewer control obligations.

(3) General Cost Considerations. The EPA also considered the fact that in general, areas that currently have, or that in the past have had, nonattainment problems under the 1-hour NAAQS, or that are in the Northeast Ozone Transport Region (OTR), have already incurred ozone control costs. The controls already implemented in these areas tend to be among the less expensive of available controls. As described in more detail below, EPA has determined that, in general, the next set of controls identified as available in the downwind nonattainment areas under the 1-hour NAAQS would cost approximately $4,300 per ton removed. By comparison, EPA has determined that the cost of the regional reductions required today would approximate $1,500 per ton removed. Thus, it appears that the upwind reductions required by today's action are more cost-effective per ton removed than reductions in the downwind nonattainment areas. Moreover, under the 1-hour NAAQS, the reductions required from each upwind State, in conjunction with reductions from other upwind States, result in ambient improvement in at least several downwind areas with nonattainment problems.

The EPA did not have available, and was not presented with, meaningful quantitative information indicating the cost-effectiveness of the regional reductions required today in light of their ambient impact downwind (e.g., the cost of emissions reductions per ppb improvement in ambient ozone levels in a downwind nonattainment area). This lack of information limited the extent to which EPA could rely on this consideration in making its determinations.

The various considerations just discussed point in the same direction as the other factors described above concerning air quality and costs. These factors and considerations lead EPA to conclude that the amounts of each upwind State's emissions that may be eliminated through highly cost-effective measures contribute significantly to nonattainment or maintenance problems downwind.

h. Interfere with Maintenance. Once a nonattainment area has attained the NAAQS, it is required to maintain that standard (e.g., sections 107(d)(3)(E)(iv), 110(a)(1)). Section 110(a)(2)(D)(i)(I) also requires that SIPs contain adequate provisions prohibiting amounts of emissions that ''interfere with maintenance by * * * any [downwind] State.'' The EPA explained and applied this requirement in the NPR as follows:

> This [interfere-with-maintenance] requirement * * * does not, by its terms, incorporate the qualifier of ''significantly.'' Even so, EPA believes that for present purposes, the term ''interfere'' should be interpreted much the same as the term ''contribute significantly,'' that is, through the same weight-of-evidence approach.
>
> With respect to the 1-hour NAAQS, the ''interfere-with-maintenance'' prong appears to be inapplicable. The EPA has determined that the 1-hour NAAQS will no longer apply to an area after EPA has determined that the area has attained that NAAQS. Under these circumstances, emissions from an upwind area cannot interfere with maintenance of the 1-hour NAAQS.
>
> With respect to the 8-hour NAAQS, the ''interfere-with-maintenance'' prong remains important. After an area has reached attainment of the 8-hour NAAQS, that area is obligated to maintain that NAAQS. (See sections 110(a)(1) and 175A.) Emissions from sources in an upwind area may interfere with that maintenance.
>
> The EPA proposes to apply much the same approach in analyzing the first component of the ''interfere-with-maintenance'' issue, which is identifying the downwind areas whose maintenance of the NAAQS may suffer interference due to upwind emissions. The EPA has analyzed the ''interfere-with-maintenance'' issue for the 8-hour NAAQS by examining areas whose current air quality is monitored as attaining the 8-hour NAAQS [or which have no current air quality monitoring], but for which air quality modeling shows nonattainment in the year 2007. This result is projected to occur, notwithstanding the imposition of certain controls required under the CAA, because of projected increases in emissions due to growth in emissions generating activity. Under these circumstances, emissions from upwind areas may interfere with the downwind area's ability to attain. Ascertaining the impact on the downwind area's air quality of the upwind area's emissions aids in determining whether the upwind emissions interfere with maintenance

(62 FR 60326).

In today's action, EPA is taking the same positions with respect to the interfere-with-maintenance test as described in the NPR. Because EPA generally interprets the ''interfere-with-maintenance'' test the same as the ''contributes-significantly-to-nonattainment'' test, for purposes of convenience, in this final rule, EPA sometimes refers to ''contributes-significantly-to-nonattainment'' to refer to both tests.

i. Dates. In today's action, EPA is determining that SIP submissions required under this rulemaking must be submitted by September 30, 1999 (see Section VI.A.1, Schedule for SIP Revision).

Further, in today's action, EPA is requiring that SIP controls required today must be implemented by no later than May 1, 2003, and they must achieve reductions computed with reference to an overall budget amount determined as of September 30, 2007 (see Section V, NO_X Control Implementation and Budget Achievement Dates).

j. Downwind Areas' Control Obligations. Commenters have argued that under the CAA, downwind States must implement additional controls before EPA may require controls in upwind States. Commenters base this argument in part on the provisions of CAA section 107(a), which provides,

> Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which [NAAQS] will be achieved and maintained within each air quality control region in such State.

Commenters further note that downwind States must implement additional reductions (beyond those specifically required by the CAA [28]) as needed to attain, under section 182(b)(1)(A)(i) and 182(c)(2)(A). The commenters add that section 179(d)(2) is a generally applicable provision that limits the stringency of required controls to what is feasible. The commenters read these provisions together to conclude that downwind States must first implement all feasible control measures in an effort to reach attainment, and only after EPA determines that such States have done so but have not reached attainment may EPA require upwind contributors to implement controls. The commenters further observe that some of the downwind States in the Northeast have not implemented all feasible SIP measures.

The EPA disagrees with this legal analysis. The provision in section 107(a) that accords to States the primary responsibility for the air quality of their air basins, in essence provides the underlying rationale for the requirement of States to submit SIP revisions that meet CAA requirements. This phrase clarifies that the requirement of assuring attainment does not fall, in the first instance, on EPA. This provision does not have implications for apportioning responsibility between the downwind State and upwind States for contributions from upwind States. Downwind States would still carry the primary responsibility of assuring clean air even after the upwind contributors have revised their SIPs to meet the requirements of section 110(a)(2)(D).

Furthermore, EPA disagrees that section 179(d)(2) has any application to today's rulemaking. That provision in essence provides a general rule that if a nonattainment area fails to attain by its attainment date, EPA may require the State to implement reasonable controls that can be ''feasibly implemented.'' This requirement is not relevant to today's rulemaking, which addresses the requirements under section 110(a)(2)(D)(i)(I) that SIPs include provisions eliminating amounts of emissions from their sources that contribute significantly to downwind nonattainment.

In addition, the requirement of downwind States to implement reductions beyond minimum CAA requirements if needed for attainment does not place the burden of implementing those reductions, in the first instance, on the downwind States. This requirement should be read to go hand-in-hand with the section 110(a)(2)(D) requirement that upwind States include SIP provisions that prohibit their sources from emitting air pollutants in amounts that ''significantly contribute'' to downwind nonattainment. In today's action, EPA is promulgating criteria for interpreting section 110(a)(2)(D) to take into account downwind attainment needs.

As a practical matter, EPA has reviewed the status of Northeast States' efforts to comply with the requirements of the 1990 CAA Amendments and has found that these States have complied with the vast majority of the SIP submission requirements. Even so, EPA is well aware that some of the States have not made certain required submissions. [29–30] However, EPA sees no basis in section 110(a)(2)(D) to mandate that downwind areas complete their SIP planning and implementation before upwind areas are required to begin that process. Upwind areas have been subject to the requirements of section 110(a)(2)(D)—in some form—since the predecessor to this provision was added in the 1977 CAA Amendments. The EPA has determined, through air quality modeling, that even after the downwind States fulfill their prescribed CAA requirements, they will have areas expected to remain in nonattainment. Under these circumstances, the downwind areas continue to constitute areas with air quality in ''nonattainment'' under section 110(a)(2)(D). As a result, upwind areas with emissions in amounts that ''significantly contribute'' to the nonattainment air quality downwind are subject to control requirements whether or not the downwind areas they affect have met all of their planning obligations.

k. Section 110(a)(2)(D) Caselaw. In the NPR, EPA noted that prior to the CAA Amendments of 1990, EPA had issued several rulemakings under section 110(a)(2)(E), the predecessor to section 110(a)(2)(D), and section 126 that addressed the issue of significant contribution in the context of pollutant transport. In those rulemakings, EPA generally applied a multi-factor test to determine whether the emissions from the sources in question constituted a signficant contribution to downwind jurisdictions. In each instance, EPA concluded that the emissions at issue from the upwind sources were not demonstrated to impact downwind air quality in a manner that would constitute significant contribution. Several of these determinations resulted in judicial challenges, but in each instance the courts upheld the Agency's determination of no significant contribution. The EPA indicated in the NPR that the prior rulemakings and the related court holdings, provide limited precedents for today's action. The EPA noted that these decisions have limited relevance because they involved different facts and circumstances, including different pollutants, different

[28] Reductions specifically required by the CAA include, for example, the 3 percent-per-year ROP reductions required of ozone nonattainment areas classified as serious or higher, under section 182(c)(2)(B).

[29–30] If downwind areas fail to meet their planning obligations, they are subject to sanctions (See Section VI, below. As EPA noted in the NPR, 62 FR 60322–23, in some instances, States in the Northeast failed to submit all of their required SIP revisions or other commitments under Phase 1 of the March 2, 1995 Memorandum and as a result, EPA initiated the sanctions process by starting sanctions clocks. In general, those States have since made the required Phase 1 submissions, and EPA terminated the sanctions process by stopping the clocks.

upwind sources, and different downwind effects.

Several commenters asserted that these prior rulemakings and cases are relevant to today's action, and compel EPA to conclude that the emissions from the upwind States affected by today's action do not contribute significantly to downwind nonattainment or maintenance problems. The EPA disagrees that these earlier determinations are controlling and that these earlier determinations are inconsistent with today's action. The EPA responds to these comments in detail in the Response to Comment document.

B. Alternative Interpretation of Section 110(a)(2)(D)

As discussed above, in the NPR EPA advanced an alternative interpretation of section 110(a)(2)(D) (62 FR 60327). Under this alternative interpretation, EPA would determine the level of emissions that significantly contribute to nonattainment downwind based on factors relating to the entire amount of upwind emissions from a particular upwind State and their ambient impact downwind. The EPA would then determine what emissions reductions must be required to adequately mitigate that significant contribution based on factors relating to cost effectiveness of reductions and attainment needs downwind.

The EPA continues to believe that this alternative interpretation remains a permissible interpretation of the statute for the reasons described in the NPR (62 FR 60327). In any event, it should be noted that for purposes of today's action, EPA finds no practical difference between the requirements that would result from the interpretation of section 110(a)(2)(D) adopted today and those that would result from the alternative interpretation described in the NPR. That is, even under the alternative interpretation, today's rulemaking would contain the same findings and require the same SIP revisions as under the interpretation adopted today (62 FR 60327).

C. Weight-of-Evidence Determination of Covered States

As discussed above, EPA applied a multi-factor approach to identify the amounts of NO_X emissions that contribute significantly to nonattainment. The EPA evaluated three air quality factors for each upwind jurisdiction (hereafter referred to as ''States'' or ''upwind States'') to determine whether each has emissions whose contributions to downwind nonattainment problems are large and/or frequent enough to be of concern. Further, for those States whose emissions are large and/or frequent enough to be of concern, EPA applied highly cost-effective controls to determine the amount of NO_x in upwind States which significantly contributes to nonattainment in, or interferes with maintenance by, a downwind State. The EPA also generally reviewed several other considerations before drawing final conclusions. Even though the actual finding of significant contribution applies only to the portion of a State's emissions for which EPA has identified highly cost-effective controls, for ease of discussion, the term ''significant'' (or like term) is used in the discussion in this section to characterize the emissions of each upwind State that make a large and/or frequent contribution to nonattainment in downwind States sufficient to warrant eliminating a portion of its emissions equivalent to what can be removed through those controls.

The purpose of this section is to describe the technical analyses performed by EPA to (a) quantify the air quality contributions from emissions in each upwind State on both 1-hour and 8-hour nonattainment, as well as 8-hour maintenance, in each downwind State, and (b) determine whether these contributions are significant.

In the proposed weight-of-evidence approach, EPA specifically applied several factors to each upwind State, as discussed in Section II.A.3.c, Definition of Significant Contribution. These factors include:

- The overall nature of ozone problem (i.e., ''collective contribution'');
- The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas; and
- The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems.

As part of the analysis of these factors, EPA considered the findings from OTAG's technical analyses, as well as the findings from a number of other studies performed by OTAG participants independent of OTAG. The major findings from these analyses are described below. This is followed by an overview of the approach used by EPA in the proposal for considering the above factors to identify States that make a significant contribution to downwind nonattainment. The comments and EPA's response to comments on EPA's weight-of-evidence proposal are then discussed. Following that discussion, the results of additional State-by-State UAM–V modeling and State-by-State CAM_X [31] source apportionment modeling performed by EPA in response to comments are summarized. [32] The EPA's analysis of the modeling results in terms of the significance of the contributions of upwind States to downwind nonattainment is presented in Section II.C.4, Confirmation of States Making a Significant Contribution to Downwind Nonattainment.

1. Major Findings From OTAG-Related Technical Analyses

The major findings from the air quality and modeling analyses by OTAG and individual OTAG participants that are most relevant to today's rulemaking are as follows:

- several different scales of transport (i.e., intercity, intrastate, interstate, and inter-regional) are important to the formation of high ozone in many areas of the East;
- emissions reductions in a given multistate region/subregion have the most effect on ozone in that same region/subregion;
- emissions reductions in a given multistate region/subregion also affect ozone in downwind multistate regions/subregions;
- downwind ozone benefits decrease with distance from the source region/subregion (i.e., farther away, less effect);
- downwind ozone benefits increase as the size of the upwind area being controlled increases, indicating that there is a cumulative benefit to extending controls over a larger area;
- downwind ozone benefits increase as upwind emissions reductions increase (the larger the upwind reduction, the greater the downwind benefits);
- a regional strategy focusing on NO_X reductions across a broad portion of the region will help mitigate the ozone problem in many areas of the East;
- both elevated and low-level NO_X reductions decrease ozone concentrations regionwide;
- there are ozone benefits across the range of controls considered by OTAG; the greatest benefits occur with the most emissions reductions; there was no ''bright line'' beyond which the benefits of emissions reductions diminish significantly;
- even with the large ozone reductions that would occur if the most

[31] Comprehensive Air Quality Model with Extensions.

[32] The UAM–V and CAM_X models are described in the Air Quality Modeling TSD.

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stringent controls considered by OTAG were implemented, there may still remain high concentrations in some portions of the OTAG region; and a regional NO_X emissions reduction strategy coupled with local NO_X and/or VOC reductions may be needed to enable attainment and maintenance of the NAAQS in this region.

The above findings provide technical evidence that transport within portions of the OTAG region results in large contributions from upwind States to ozone in downwind areas, and that a regionwide approach to reduce NO_X emissions is an effective way to address these interstate contributions.

2. Summary of Notice of Proposed Rulemaking Weight-of-Evidence Approach

The EPA relied on OTAG data to develop the information necessary to evaluate the weight-of-evidence factors identified above. These data include emissions (tons) and emission density (tons per square mile), air quality analyses, trajectory, wind vector, and ''ozone cloud'' analyses, and subregional zero-out modeling. In brief, EPA's proposed approach was as follows:

- the OTAG transport distance scale was applied to identify, based on the meteorological potential for transport, which States may contribute to ozone in downwind States;
- the results of the OTAG subregional modeling runs (described below) were used to quantify the extent to which each subregion contributes to downwind nonattainment for the 1-hour and/or 8-hour NAAQS;
- the OTAG 2007 Base Case NO_X emissions and emissions density were used to identify States which emit large amounts of NO_X and/or have a high density of NO_X emissions compared to other States in the OTAG region and, therefore, have NO_X emissions which may be great enough to contribute to downwind nonattainment; and the OTAG 2007 Base Case NO_X emissions were also used to translate the findings from the subregional modeling to a State-by-State basis.

a. Quantification of Contributions. As part of OTAG's assessment of transport, a series of model runs were performed to examine the impacts of emissions from each of 12 multistate subregions on ozone in downwind areas. The locations of these subregions are shown in Figure II–1.

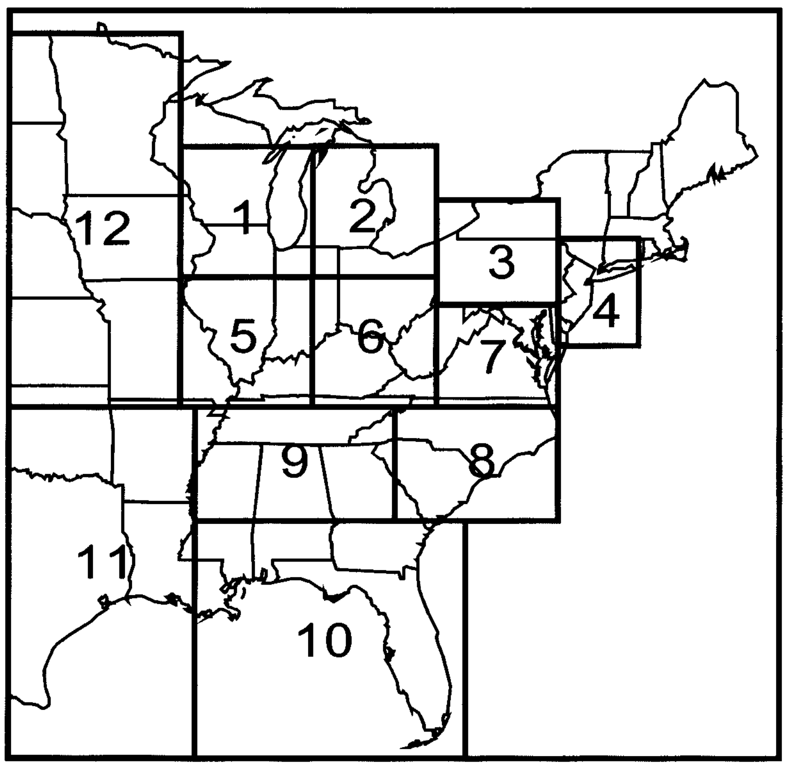

Figure II-1. OTAG Subregions

In each subregional model run, all manmade emissions were removed from one upwind subregion and the model was run for the OTAG July 1988 and 1995 episodes. The ''parts per billion (ppb)'' differences in ozone between each subregional zero-out run compared to the corresponding 2007 Base Case run were used to quantify the air quality impacts of the subregion on nonattainment downwind.

In the proposed NO_X SIP call, EPA considered areas as ''nonattainment'' if air quality monitoring indicates that the area is currently measuring nonattainment and if air quality modeling indicates future nonattainment, taking into account CAA control requirements and growth. In this regard, areas were considered nonattainment for the 1-hour NAAQS if they had 1994–1996 [33] monitoring data indicating measured 1-hour violations and 2007 Base Case 1-hour predictions >=125 ppb. Areas were considered to be nonattainment for the 8-hour NAAQS if they had 1994–1996 monitoring data indicating measured 8-hour violations and 2007 Base Case 8-hour predictions >=85 ppb. The inconsistency between the form of the 8-hour NAAQS, which considers 3 years of data for determining the average of the fourth-highest 8-hour daily maximum concentration at a monitor, and the limited predictions available from the OTAG episodes introduced a complication to the analysis of 8-hour contributions. It was not possible to use the model predictions in a way that explicitly matched the form of the 8-hour NAAQS. Instead, an analysis of seasonal and episodic ozone measurements was performed in an attempt to link 8-hour measured concentrations during the OTAG episodes to the form of the 8-hour NAAQS, as closely as possible. The results of that analysis indicated that the 3-episode average of the second highest 8-hour ozone concentrations measured during the OTAG 1991, 1993, and 1995 episodes corresponded best, overall, to the 3-year average of the fourth highest 8-hour daily ambient data. However, since OTAG subregional modeling was only available for the 1988 and 1995 episodes, EPA used the concentrations during these two episodes in calculating average second high 8-hour concentrations. [34]

b. Evaluation of 1-Hour and 8-Hour Contributions. In the proposal, EPA summarized the ''ppb'' contributions to downwind nonattainment from each subregion in terms of both the frequency and the magnitude of the downwind impacts over specific concentration ranges (e.g., 2 to 5 ppb, 5 to 10 ppb, 10 to 15 ppb, etc.). The results indicate that, in general, large contributions to downwind nonattainment occur on numerous occasions. Although the level of downwind contribution varies from subregion to subregion, a consistent pattern is apparent for both 1-hour nonattainment and 8-hour nonattainment. Specifically, the results of the subregional modeling indicate that emissions from States in subregions 1 through 9 produce large 1-hour and 8-hour contributions downwind in terms of the magnitude and frequency, including geographic extent, of the downwind impacts. In addition, nonattainment areas within many States in the OTAG region receive large and/or frequent contributions from emissions in these subregions. The EPA proposed to find that most of the States whose emissions are wholly or partially contained within one or more of these subregions (i.e., Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin, as well as the District of Columbia) are making a significant contribution to downwind nonattainment. In addition to the ambient impact demonstrated by the subregional modeling, this proposed finding was based on a determination that:

- OTAG strategy modeling and non-OTAG modeling indicate that NO_X emissions reductions across these States would produce large reductions in 1-hour and 8-hour ozone concentrations across broad portions of the region including 1-hour and 8-hour nonattainment areas;
- these States are upwind from nonattainment areas within the 1- to 2- day distance scale of transport;
- these States form a contiguous area of manmade emissions covering most of the core portion of the OTAG region;
- 11 of the States that are wholly within subregions 1 through 9 have a relatively high level of NO_X emissions from sources in their States; these States are ranked in the top 50 percent of all States in the region in terms of total NO_X emissions and/or have NO_X emissions exceeding 1000 tons per day;
- States wholly within subregions 1 through 9 with lesser emissions have a relatively high density of NO_X emissions;
- for the seven States that are only partially contained in one of subregions 1 through 9, the State total NO_X emissions, as well as each State's contribution to NO_X emissions in the subregions in which they are located, indicate that six of the States each have: NO_X emissions that are more than 10 percent of the total NO_X emissions in one of these subregions, NO_X emissions in the top 50 percent among all States, and/or a majority of its NO_X emissions within one of these subregions.

For the New England States that were not included in any of the OTAG zero- out subregions, EPA found that two of these States (i.e., Massachusetts and Rhode Island) have a high density of NO_X emissions. Also, the trajectory and wind vector analyses indicated that these States are immediately upwind of nonattainment areas in other States.

For the nine States in the OTAG region which are wholly within subregions 10, 11, and 12 (i.e., Florida, Kansas, Louisiana, Minnesota, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas), and for Arkansas, Iowa, and Mississippi, EPA proposed that emissions from each of these States should be considered not to significantly contribute to downwind nonattainment. These States are further discussed below in Section II.C.5, States Not Covered by this Rulemaking.

c. Comments and Responses on Proposed Weight-of-Evidence Approach to Significant Contribution. The EPA received a number of comments on various elements of the proposed weight-of-evidence approach. In addition, EPA received new modeling and analyses performed by commenters which address the issue of significant contribution. The following is a summary of the major comments received by EPA and the responses to these comments. Additional comments and EPA's response to these comments are provided in the Response to Comment document.

Comment: Some commenters stated that it was inappropriate to use a weight-of-evidence approach to determine the significance of upwind emissions on downwind nonattainment. Rather, it was argued that EPA should use a specific ''bright line'' criterion. Other commenters supported the weight-of-evidence approach.

Response: The magnitude and frequency of contributions from an upwind State to downwind nonattainment depend on the extent of the nonattainment problem in the downwind area, the emissions in the downwind area, the emissions in the upwind State, the distance between the upwind State and the downwind area, and weather conditions (i.e., winds and temperatures which favor ozone formation and transport). Because these factors vary in a complex way across the OTAG region, it is not possible to develop a single bright line test for significance that will be applicable and appropriate for all potential upwind-State-to-downwind-area linkages. Therefore, EPA believes that it is more appropriate to use a weight-of-evidence approach to account for all of these factors than establishing a bright line criterion.

Comment: Some commented that EPA should not use the trajectory, wind vector, and ''ozone cloud'' analyses as a

[33] Data for 1994–1996 were used because these were the most recent quality-assured data available at the time the analysis was performed.

[34] In response to comments, EPA has reexamined the method for relating 8-hour model predictions during the OTAG episodes to the form of the 8-hour NAAQS. This is discussed further in Section II.C.2.c, Comments and Responses on the Proposed Weight of Evidence Approach to Significant Contribution.

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basis for determining significant contribution because these techniques indicate air movement and do not account for ozone formation and depletion due to photochemical reactions and other processes. Other commenters argued in favor of using this information as means of linking upwind States with downwind nonattainment.

Response: The EPA agrees that information from such techniques should not be used as the sole basis for finding that certain upwind States significantly contribute to nonattainment in specific downwind States. However, EPA believes that it is important to consider the ''movement'' of ozone and/or precursors as part of the air quality evaluation of contributions from upwind States. This factor is incorporated into the air quality models used by EPA for this rulemaking. The inclusion of this information, in conjunction with numerous other air quality factors in the models, provides for a more technically robust analysis than can be provided by the trajectory, ozone cloud, and wind vector analyses alone.

Comment: A number of commenters stated that CAA section 110(a)(2)(D) requires a State-by-State demonstration that emissions within an upwind State make a significant contribution to nonattainment in another State and thus, EPA's proposed approach of using subregional (i.e., multistate) modeling, together with each upwind State's NO_X emissions, to establish these linkages is legally flawed. These commenters argued that section 110(a)(2)(D) requires ''each implementation plan submitted by a State'' to contain provisions that prohibit any source or other type of emissions activity ''within the State'' from emitting air pollutants in amounts that contribute significantly to a downwind nonattainment problem. The commenters concluded that these provisions require, as a matter of technical procedure, that EPA must base its determination that emissions from a particular State significantly contribute to nonattainment downwind on a technical analysis of that particular State's emissions. According to the commenters, section 110(a)(2)(D) by its terms, prohibits EPA from making that technical determination by examining the impact of emissions from a group of States on a downwind nonattainment problem, and then extrapolating from that information to determine whether emissions from each State within that group should be considered to make a significant contribution.

As a technical matter, these commenters argue that if emissions from more than one State are lumped together in assessing the contribution to a downwind State, there is no way to determine the amount of emissions in each contributing State that must be reduced. The commenters argue that the only way to establish specific upwind State to downwind State linkages is through air quality modeling on a State-by-State basis. Further, the commenters contend that once an area beyond a particular State's boundaries is modeled, there is no way of knowing how much farther upwind to go in terms of defining a source area. In order to address these issues, many commenters stated that EPA must do State-by-State zero-out UAM–V modeling and/or State- by-State source apportionment modeling using the CAMx model to determine downwind contributions from upwind States.

Response: On the legal issue, EPA disagrees that the above-referenced provisions of section 110(a)(2)(D), by their terms, mandate the technical procedure for EPA to make the determination of significant contribution. These provisions simply indicate that EPA must make that determination on a SIP-by-SIP basis, that is, for EPA to issue a SIP call with respect to a particular State, EPA must determine that the provisions of that SIP fail to adequately control emissions from sources within the State. However, these provisions do not mandate any particular technical procedure for making that determination. As a result, EPA may employ any technical procedure that is sufficiently accurate. As discussed below, EPA believes that its subregional approach is sufficiently accurate to justify the SIP call. However, in response to this and other comments, EPA did conduct State-by-State modeling. The results of this modeling, as discussed below, confirm the results of the subregional modeling.

On the technical issue, EPA used the subregional modeling as part of the proposed approach because OTAG had developed and relied on this modeling as part of its analysis to quantify the impacts of manmade emissions in upwind areas on ozone in downwind areas. In addition, in conjunction with other information, EPA believes that it is possible to make rational extrapolations from the subregional results in order to draw conclusions as to the contribution of individual States. The EPA believes that it is credible to use NO_x emissions in each State, along with the subregional modeling results, in the determination of significance in view of the results of OTAG modeling which indicate that, in addition to local emissions, the level of ozone in a downwind State is directly related to the magnitude of NO_x emissions in upwind areas and the proximity of the upwind area to the downwind State. A more detailed discussion of the technical validity of the subregional modeling is contained in the Response to Comment Document.

The EPA recognizes that State-by-State modeling would provide some additional precision to the magnitude and frequency of individual State-to-State contributions. In response to the recommendations for additional modeling, EPA performed both State-by-State UAM–V zero-out modeling and State-by-State CAMx source apportionment modeling for many of the upwind States in the OTAG region which were proposed as significant contributors. The EPA's analysis of the contributions to downwind nonattainment using the State-by-State modeling confirms the overall finding, based on the proposed subregional modeling, that the 23 jurisdictions identified in the proposal significantly contribute to nonattainment in downwind States. Specifically, the subregional modeling indicates that manmade emissions from sources in subregions 1 through 9 make large and/ or frequent contributions to 1-hour and 8-hour nonattainment in specific downwind States. The EPA's analysis of the State-by-State modeling demonstrates that each of the 23 upwind jurisdictions identified through subregional modeling significantly contribute to nonattainment in specific downwind States. In addition, the results of the State-by-State modeling show that the specific upwind-State-to-downwind-nonattainment linkages indicated by the subregional modeling are confirmed overall by the State-by-State modeling. The State-by-State modeling analyses are summarized below and more fully documented in the Air Quality Modeling TSD.

Comment: The EPA received comments that zero-out modeling introduces sharp spatial changes in emissions and pollutants along the edges of the zero-out area. The commenters contend that this is not credible and provides an incorrect assessment of transport.

Response: The EPA disagrees with this comment, as discussed in the Response to Comments document. Also, as indicated above, in response to other comments, EPA has performed CAMx source apportionment modeling which does not use a zero-out technique for quantifying ozone contributions from upwind States. In general, EPA has found that the source apportionment technique and zero-out modeling

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provide consistent information on the relative contribution of upwind States to downwind nonattainment. In cases where the two techniques do not provide consistent results, the source apportionment technique tends to indicate larger contributions than the zero-out modeling. The differences between these two modeling techniques are described further in the Air Quality Modeling TSD.

Comment: Some comments referenced a study which analyzed the ''noise'' (i.e., uncertainty) in the UAM–V modeling system. This study purports to show that the contributions from some States EPA proposed as significant are within the ''noise'' of the model.

Response: This study focuses on model uncertainty by varying many, but not all, inputs to the model. The study does not contend that the inputs selected by OTAG are incorrect, but rather that there may be other plausible values for these inputs. The results indicate that there is a range of uncertainty in predicted ozone associated with the range of possible values for the particular inputs studied by the commenter. The study does not indicate that there is any bias in the model's predictions (i.e., there is no indication that the predictions are too high or too low). The specific values for the inputs being used by EPA in its air quality modeling are the same values that were used by OTAG. These values were selected by the OTAG Regional and Urban Scale Modeling Work Group, which included experts in air quality modeling from the public and private sector, in conjunction with the model's developers, Systems Application International. The predictions from OTAG's model runs using these same input values were evaluated against ambient measurements and found by OTAG to provide acceptable results. The EPA continues to believe that the specific inputs selected by OTAG are technically sound and the modeling results are credible. A further discussion of EPA's response to this comment is in the Response to Comments document.

Comment: Several commenters stated that emissions from large point sources of NO_x in specific States do not contribute significantly to downwind nonattainment.

Response: As discussed in Section II.A.3.c, Definition of Significant Contribution, under EPA's collective contribution approach, if emissions in the aggregate from a particular geographic region or State are found to contribute significantly to nonattainment downwind, then the emissions in that region or State are considered to be significant contributors to that nonattainment problem. Moreover, EPA treats emissions as ''contributing significantly'' only to the extent they may be eliminated through highly cost-effective reductions. Thus, if all emissions from a State, when considered in the aggregate, are found to contribute significantly to nonattainment downwind, and if there are highly cost-effective controls for NO_x emissions from sources in the upwind State, then the amount of NO_x emissions from these sources that can be eliminated with such controls are considered to be making a significant contribution. The amount of emissions determined through this approach to make a significant contribution may be relatively small, compared to the upwind State's entire inventory; and the ambient impact downwind of eliminating that amount may be relatively small as well. However, this small impact does not mean that the emissions themselves are not significant insofar as their contribution to nonattainment downwind. Further, as discussed in Section IV, Air Quality Assessment, when the amount of emissions required to be eliminated from upwind States are combined and modeled collectively, their ambient impact downwind is larger.

Comment: One commenter provided a recommendation for dealing with the concern that the spatial resolution of meteorological inputs to the air quality model may be too coarse to require that predicted exceedences correspond exactly with a county violating the NAAQS. The commenter's recommendations were to base the selection of 1-hour nonattainment receptors on model predicted exceedences in either (a) all counties within the metropolitan statistical area containing the nonattainment area or (b) all counties comprising the designated 1-hour nonattainment area.

Response: The EPA believes that the appropriate way to address this issue is to use all counties comprising the designated 1-hour nonattainment area. That is, all counties in a designated 1- hour nonattainment area should be considered as possible nonattainment receptors for the purposes of evaluating contributions to nonattainment under the 1-hour NAAQS. The EPA recognizes that not all counties within a designated nonattainment area have monitors, and that some counties may have monitors that indicate attainment in that county. Even so, EPA recognizes that under the 1-hour NAAQS, nonattainment boundaries are generally used to describe an area with the nonattainment problem. Thus, EPA believes that this geographic vicinity offers the best indication of an area that may be expected to have nonattainment air quality somewhere within its boundaries. The EPA believes that it is appropriate to include all counties in the designated nonattainment area because the entire nonattainment area is responsible for meeting the 1-hour NAAQS, even if only one monitor measures nonattainment at any one time. As noted elsewhere, EPA predicts that many 1-hour nonattainment areas that currently monitor nonattainment somewhere within the area will remain in nonattainment in 2007, in some cases because of predicted violations in counties that currently monitor attainment. The EPA believes that the entire area should be considered to be in nonattainment until all monitors in the area indicate attainment of the NAAQS. Thus, in today's rulemaking, EPA used the designated 1-hour nonattainment area in selecting the receptors to be used to evaluate impacts on downwind nonattainment problems.

Comment: Several commenters questioned the validity of EPA's approach of using the 3-episode average of the second highest 8-hour daily maximum concentration to represent the form of the 8-hour NAAQS (i.e., the 3-year average of the fourth highest 8-hour daily maximum values at a monitor [35]). Commenters expressed the concern that the average second high may not be representative for all areas across the OTAG domain. However, none of the commenters provided any suggested alternatives to EPA's approach.

Response: The analysis performed by EPA to establish a relationship between the air quality during the OTAG episodes and the form of the 8-hour NAAQS was based upon an analysis of 3 years of monitoring data compared to monitoring data during the OTAG episodes. In response to comments, EPA performed an analysis to determine how the predicted average second high 8-hour values, as well as several alternative 8-hour values, compared to ambient 8-hour design values, based on 1994 to 1996 measured data. Based on this analysis, EPA determined that, overall, the model-predicted average second high values underestimate the corresponding ambient design values for those counties in the OTAG domain with 1994–1996 ambient values >=85 ppb. In addition to the average second high, EPA also compared six other measures of 8-hour model predictions to ambient design values. The six other measures include the highest, second

[35] For the purposes of discussion in this Section, these values are referred to as ''design'' values.

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highest, third highest, and fourth highest ozone predictions across the July 1991, 1993, and 1995 episodes; the 3-episode average of the highest concentrations; and the 3-episode average of the highest, second highest, and third highest concentrations. The EPA also developed the same measures using model predictions from all 4 episodes for comparison to the ambient design values. The results indicate that none of the alternative measures provides a universal best match to ambient 8-hour design values in all States. Each of the indicators overestimates values in some areas and underestimates values in other areas to a varying extent. Furthermore, the best representation of 8-hour design values using predictions from the OTAG episodes varies from State to State. Given that the predicted average second high underestimates ambient 8-hour design values and that none of the other 8-hour indicators examined by EPA provides a ''best'' match to ambient values in all cases, EPA has decided to analyze the contributions to 8-hour nonattainment problems using all 8- hour predictions >=85 ppb. The EPA believes that this approach is appropriate given that EPA is using modeling results for the 8-hour NAAQS merely as an indicator of the likelihood that areas that currently monitor violations of the 8-hour NAAQS will continue to be nonattainment for the 8-hour NAAQS and/or have 8-hour maintenance problems in 2007. [36] Thus, the air quality analysis of 8-hour contributions, described below, focuses on all 8-hour values >=85 ppb.

Comment: Several commenters submitted new State-by-State zero-out modeling using UAM–V and CAM $_x$ source apportionment modeling purporting to show that contributions from particular upwind States are insignificant.

Response: The EPA reviewed the commenters' modeling to determine and assess (a) the technical aspects of the models that were applied; (b) the types of episodes modeled; (c) the methods for aggregating, analyzing, and presenting the results; (d) the completeness and applicability of the information provided; and (e) whether the technical evidence supports the arguments made by the commenters. Overall, the modeling submitted by commenters is viewed by EPA as generally technically credible, although not complete in all cases. The EPA's ability to fully evaluate and utilize the modeling submitted by commenters was hampered in some cases because only limited information on the results was provided. For example, a commenter may have provided results for only 1 or 2 days in an episode, or for only one of several episodes with no information presented on the results for the remaining days or episodes that were modeled. As another example, results were presented for only the peak ozone day in an episode while greater contributions may have been predicted on other high ozone days of the episode. For some of the modeling, the information was only presented in graphical form which made the results difficult to evaluate in a quantitative way. Also, in some cases the model predictions were only presented as episode composite values without information on peak contributions. The EPA's full assessment of the modeling submitted by commenters is provided in the Response to Comments document.

In light of the absence of complete information in the modeling provided by commenters and other comments calling for State-by-State analyses, EPA decided to perform additional air quality modeling of the type submitted by commenters in order to consider all of the data resulting from such model runs. The EPA modeling includes State-by-State zero-out modeling using UAM–V and State-by-State CAM $_x$ source apportionment modeling.

EPA conducted further analysis of other factors included in the multi-factor approach for significant contribution. The results of EPA's consideration of these factors and EPA's modeling are described next.

3. Analysis of State-specific Air Quality Factors

a. Overall Nature of Ozone Problem (''Collective Contribution''). As described above, EPA believes that each ozone nonattainment problem at issue in today's rulemaking is the result of emissions from numerous sources over a broad geographic area. The contribution from sources in an upwind State must be evaluated in this context. This ''collective contribution'' nature of the ozone problem supports the proposition that the solution to the problem lies in a range of controls covering sources in a broad area, including upwind sources that cause a substantial portion of the ozone problem. This upwind share is typically caused by NOx emissions from sources in numerous States. States adjacent to the State with the nonattainment problem generally make the largest contribution, but States further upwind, collectively, make a contribution that constitutes a large percentage in the context of the overall problem. As an example to illustrate the overall nature of the ozone problem, EPA discusses below the ozone problem in the New York City nonattainment area.

b. Extent of Downwind Nonattainment Problems. For each downwind area to which an upwind State may be linked, EPA also examined the extent of the downwind nonattainment problem, including the air quality impacts of controls required in downwind areas under the CAA, as well as of controls required or implemented on a national basis. As indicated elsewhere, EPA determined that a downwind area should be considered ''nonattainment'' for purposes of section 110(a)(2)(D)(i)(I) under the 1-hour NAAQS if the area currently (as of the 1994–96 time period) has nonattainment air quality [37] and if the area is modeled to have nonattainment air quality in the year 2007, after implementation of all measures specifically required of the area under the CAA as well as implementation of Federal measures required or expected to be implemented by that date. The EPA determined that each such downwind area had a residual nonattainment problem even after implementation of all these control measures. The presence of residual nonattainment is a factor that supports the need to reduce emissions from upwind sources to allow further progress towards attainment. [38] As an example, the residual nonattainment for the New York City area is discussed in more detail below.

[36] Similarly, the EPA is also using 1-hour model predictions >=125 ppb as an indicator that areas currently designated nonattainment for the 1-hour NAAQS will continue to be nonattainment for the 1-hour NAAQS in 2007.

[37] As explained elsewhere, for the 1-hour standard, EPA based its determination as to the boundaries of the area with air quality violating the NAAQS on the boundaries of the area designated as nonattainment.

[38] Indeed, the modeling relied on in today's action indicates that many downwind nonattainment areas carry a residual nonattainment problem even after implementation of regional reductions by all the States affected by today's action. Although not essential to EPA's conclusions, the presence of this nonattainment problem even after implementation of regional controls, based on the modeling used in today's rulemaking, indicates that even further reductions, regionally or locally, would be needed to assure attainment in those downwind areas.

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c. Air Quality Impacts of Upwind Emissions on Downwind Nonattainment. As indicated above, in response to comments, additional air quality modeling was performed by EPA to confirm the proposed approach which relied on subregional modeling to quantify the impacts of emissions from upwind States on nonattainment in downwind areas. The additional modeling consisted of State-by-State zero-out modeling using UAM–V and State-by-State source apportionment modeling using the CAMx Anthropogenic Precursor Culpability Assessment (APCA) technique. [39] A description of these models is contained in the Air Quality Modeling TSD. Both models are currently being used by the scientific and regulatory community for air quality assessments. The EPA is not aware of any information that would indicate that either model provides more credible predictions than the other. Each modeling technique (i.e., zero-out and source apportionment) provides a different technical approach to quantifying the downwind impact of emissions in upwind States. The zero- out modeling analysis provides an estimate of downwind impacts by comparing the model predictions from a Base Case run to the predictions from a run in which the Base Case manmade emissions are removed from a specific State. In contrast, the source apportionment modeling quantifies downwind impacts by tracking formation, chemical transformation, depletion, and transport of ozone formed from emissions in an upwind source area and the impacts that ozone has on nonattainment in downwind areas. The EPA ran both models for all four OTAG episodes (i.e., July 1–11, 1988; July 13–21, 1991; July 20–30, 1993; and July 7–18, 1995) using the 2007 SIP Call Base Case emissions. The development of emissions for this Base Case scenario are described in Section IV, Air Quality Assessment.

The EPA selected several metrics in order to evaluate the downwind contributions from emissions in upwind States. The metrics were designed to provide information on the three fundamental factors for evaluating whether emissions in an upwind State make large and/or frequent contributions to downwind nonattainment. These factors are (a) the magnitude of the contribution, (b) the frequency of the contribution, and (c) the relative amount of the contribution. The magnitude of contribution factor refers to the actual amount of ''ppbs'' of ozone contributed by emissions in the upwind State to nonattainment in the downwind area. The frequency of the contribution refers to how often the contributions occur and how extensive the contributions are in terms of the number of grids in the downwind area that are affected by emissions in the upwind State. The relative amount of the contribution is used to compare the total ''ppb'' contributed by the upwind State to the total ''ppb'' of nonattainment in the downwind area.

As indicated above, two modeling techniques (i.e., UAM–V zero-out and CAMx source apportionment) were used for the State-by-State evaluation of contributions. The EPA developed metrics for both modeling techniques for each of the three factors. However, because of the differences between the two techniques, some of the metrics used for the UAM–V modeling and the CAMx modeling are different. The specific UAM–V and CAMx metrics and how they relate to the three factors used for the evaluation of contributions are described below.

The EPA examined the contributions from upwind States to downwind nonattainment for several types of nonattainment receptors. Nonattainment receptors for the 1-hour analysis include those grid cells that (a) are associated with counties designated as nonattainment for the 1-hour NAAQS and (b) have 1-hour Base Case model predictions >=125 ppb. These grid cells are referred to as ''designated plus modeled'' nonattainment receptors. Using these receptors, the metrics were calculated for each 1-hour nonattainment area as well as for each State. To calculate the metrics by State, all of the 1-hour nonattainment receptors in that State were pooled together. [40] Table II–1 lists the 1-hour nonattainment areas that were considered in this analysis, along with the State(s) in which the nonattainment area is located. In addition to the areas listed in Table II–1, EPA also evaluated the contributions of upwind States to ozone concentrations over Lake Michigan because modeled air quality over the lake can be indicative, under certain weather conditions, of air quality in portions of the States surrounding the lake. [41]

TABLE II–1.—1-HOUR NONATTAINMENT AREAS EVALUATED

Nonattainment area	State(s)
Atlanta	Georgia.
Baltimore	Maryland.
Birmingham	Alabama.
Boston/Portsmouth 1	Massachusetts, New Hampshire.
Chicago/Milwaukee [2]	Illinois, Indiana, Wisconsin.
Cincinnati	Kentucky, Ohio.
Greater Connecticut	Connecticut.
Louisville	Indiana, Kentucky.
Memphis	Mississippi, Tennessee.
New York City	Connecticut, New Jersey, New York.
Philadelphia	Delaware, Maryland, New Jersey, Pennsylvania.
Pittsburgh	Pennsylvania.
Portland	Maine.
Rhode Island	Rhode Island.
Southwestern Michigan [3]	Michigan.

[39] For ease of discussion, EPA is using the term ''UAM–V'' to refer to the UAM–V State-by-State zero-out modeling and the term ''CAMx'' to refer to the CAMx source apportionment modeling.

[40] For ease of discussion in this Section, the 1- hour nonattainment areas and the set of nonattainment receptors pooled over an entire State are referred to as downwind areas.

[41] High measured ozone concentrations in portions of Illinois, Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan are often associated with weather conditions which cause ozone precursor pollutants to be blown offshore over the lake during the morning, where they can form high ozone concentrations which then return onshore during ''lake breeze'' wind flows in the afternoon. Because the size of the grid cells used in the OTAG modeling is relatively large compared to the spatial scale of the lake breeze, the high ozone concentrations predicted over the lake may not be blown back onshore in the model. Since high concentrations over the lake do, in reality, impact air quality along the shoreline of one or more of these States, the EPA believes that it is appropriate to use predicted contributions to ozone over Lake Michigan as a surrogate for contributions to any one of the surrounding States (i.e., Illinois, Indiana, Michigan, and Wisconsin).

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TABLE II–1.—1-HOUR NONATTAINMENT AREAS EVALUATED—Continued

Nonattainment area	State(s)
St. Louis	Illinois, Missouri.
Washington, DC	District of Columbia, Maryland, Virginia.
Western Massachusetts	Massachusetts.

[1] For the purposes of this analysis EPA has combined the Greater Boston nonattainment area which includes portions of Massachusetts and New Hampshire, with the Portsmouth, New Hampshire nonattainment area into a single downwind nonattainment receptor area.
[2] For the purposes of this analysis EPA has combined the 1-hour nonattainment counties that are along the shoreline of Lake Michigan in the States of Illinois, Indiana, and Wisconsin into a single downwind nonattainment receptor area.
[3] For the purposes of this analysis EPA has combined the 1-hour nonattainment counties that are along the shoreline of Lake Michigan in the State of Michigan into a single downwind nonattainment receptor area.

For the 8-hour analysis, nonattainment receptors are those grid cells that (a) are associated with counties currently violating the 8-hour NAAQS (based on 1994–1996 data) and (b) have 8-hour Base Case model predictions >=85 ppb. These grid cells are referred to as ''violating plus modeled'' nonattainment receptors. The metrics for the 8-hour contribution analyses were calculated on a State-by-State basis by pooling together the ''violating plus modeled'' receptors in a State.

(1) UAM–V State-by-State Modeling. In the UAM–V zero-out model runs all manmade emissions in a given upwind State were removed from the Base Case scenario. Each zero-out scenario was run for all 4 episodes and the ozone predictions in downwind States were then compared to those from the Base Case run in order to quantify the downwind impacts of emissions from the upwind State (i.e., the State in which the manmade emissions were removed). The EPA performed zero-out runs for the following set of States:

- Alabama, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Michigan, Missouri, North Carolina, Ohio, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Zero-out modeling for Massachusetts was performed because this State was the only State in the Northeast with relatively large NO_X emissions that was not included in any of the OTAG subregional modeling. The other States listed above were selected for zero-out modeling in order to respond to comments that emissions in all or portions of each of these States do not contribute significantly to downwind nonattainment.

The EPA analyzed the model-predicted ozone concentrations from the zero-out runs using the four metrics described below. The results for these metrics are too voluminous to include in the notice in their entirety. The full set of results is contained in the Air Quality Modeling TSD. Each metric was calculated using 1-hour daily maximum concentrations >=125 ppb as well as 8-hour daily maximum concentrations >=85 ppb. Model predictions from all 4 episodes were used for calculating the metrics. [42]

UAM–V Metric 1: Exceedences. This metric is the total number of predicted concentrations exceeding the NAAQS (i.e. 1-hour values >=125 ppb and 8- hour values >=85 ppb) within the downwind area. In calculating this metric, EPA summed the number of occurrences of values above the applicable standard (i.e., 1-hour or 8-hour) for all nonattainment receptors within the downwind area. For example, in Downwind Area #1 there are five 1-hour ''designated plus modeled'' nonattainment receptors. For this downwind area, the Base Case value for Metric 1 is calculated by first counting the number of days, across all four episodes, that had 1-hour daily maximum values >=125 ppb at each of the five receptors. The result is the total number of exceedences at each receptor over all days in all four episodes. The total number of exceedences at each receptor is then summed across all five receptors to produce the total number of exceedences in Downwind Area #1, which is the value for Metric 1 for this area.

UAM–V Metric 2: Ozone Reduced—ppb. This metric shows the magnitude and frequency of the ''ppb'' impacts from each upwind State on ozone concentrations in each downwind area. These impacts are quantified by calculating the difference in ozone concentrations between the zero-out run and the Base Case. The results are then tabulated in terms of the number of ''impacts'' within six concentration ranges: >=2 to 5 ppb, >=5 to 10, >=10 to 15, >=15 to 20, >=20 to 25, and >=25 ppb. The impacts for 1-hour daily maximum values and 8-hour daily maximum values are determined by tallying the total ''number of days and grid cells'' >=125 ppb or >=85 ppb that receive contributions within the concentration ranges. In the analysis of contributions, as described below, the data from Metric 2 are used in conjunction with Metric 1 to determine the percent of the exceedences in the downwind area that receive contributions of >=2 ppb, >= 5 ppb, >=10, ppb, etc. The maximum ''ppb'' impact within the downwind area is also calculated.

UAM–V Metric 3: Total ppb Reduced. This metric quantifies the total ppb contributed in the downwind area from an upwind State, not including that portion of the contribution that occurs below the level of the NAAQS. For 1-hour concentrations, Metric 3 is calculated by taking the difference between the Base Case predictions in each nonattainment receptor and either (a) the corresponding value in the zero-out run, or (b) 125 ppb, whichever is greater (i.e., 125 ppb or the prediction in the zero-out run). The Base Case vs. zero-out differences are summed over all days and across all nonattainment receptors in the downwind area. The calculation of this metric is illustrated by the following example. If the Base Case 1-hour daily maximum ozone prediction is 150 ppb and the corresponding value from the zero-out run is 130 ppb, then the difference used in this metric is 20 ppb. However, if the value from the zero-out run is 115 ppb, then the difference used in this metric is 25 ppb (i.e., 150 ppb–125 ppb, because 115 ppb is less than 125 ppb). For analyzing the contributions using Metric 3, the values of this metric are compared to the total amount of ozone above the NAAQS (i.e., 125 ppb, 1-hour or 85 ppb, 8-hour) in the Base Case. This baseline measure of the ''total amount of nonattainment'' (i.e., the total ''ppb'' of ozone that is above the NAAQS) is calculated by summing the ''ppb'' values in the Base Case that are above the level of the NAAQS. The total contribution from an upwind State to a particular downwind area calculated by Metric 3 is expressed in relation to the

[42] Model predictions from the first few days of each episode are considered ''ramp-up'' days and were excluded from the analysis, following the procedures adopted by OTAG. The ramp-up days include the first 3 days of the July 1988, 1991, and 1995 episodes and the first 2 days of the July 1993 episode.

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amount that the downwind area is in nonattainment. For example, if Upwind State #1 contributes a total of 50 ppb >=125 ppb to Downwind Area #2 and the total Base Case ozone >=125 ppb in Downwind Area #2 is 500 ppb, then the contribution from Upwind State #1 (i.e., 50 ppb) to Downwind Area #2 is equivalent to 10 percent of Downwind Area #2's nonattainment problem (i.e., 50 ppb divided by 500 ppb, times 100).

UAM–V Metric 4: Population-Weighted Total ppb Reduced. This metric is similar to the ''Total ppb Reduced'' metric except that the calculated contributions are weighted by (i.e., multiplied by) population. In calculating this metric, the ''ppb'' contributions are determined for each nonattainment receptor, then summed across all nonattainment receptors in a particular downwind area. During this calculation, the population in the nonattainment receptor is multiplied by the total contribution in that receptor (i.e., grid cell) and then this value is added to the corresponding values for the other receptors in the downwind area. The results for this metric are expressed relative to the population-weighted Base Case amount similar to the approach followed with Metric 3, as described above.

(2) CAMx Source Apportionment Modeling. In the CAMx modeling, the source apportionment technique was used to calculate the contributions from upwind States to ozone concentrations above the NAAQS in downwind areas. Due to computational constraints, it was not possible for EPA to treat each State in the OTAG region as a separate source area. Several of the smaller States in the Northeast were grouped together as were seven States in the far western portion of the region. The following States were treated as individual source areas:

- Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

The following States were grouped together:

- Connecticut and Rhode Island were combined; Maryland, Delaware and the District of Columbia were combined; New Hampshire and Vermont were combined; and Arkansas was combined with the portions of Oklahoma, Kansas, Minnesota, Nebraska, North Dakota, and South Dakota that lie within the OTAG region.

The contributions from each of these source areas to downwind nonattainment were evaluated using four metrics. As indicated above, the CAMx metrics are calculated for the same types of nonattainment receptors as the UAM–V zero-out metrics. The CAMx metrics are calculated in a way that is different from the metrics used for the zero-out runs in large part because of the differences between the two techniques. The zero-out modeling calculates contributions using the difference in predictions between two model runs (i.e., a Base Case and a State-specific zero-out run). In contrast, the CAMx source apportionment technique calculates contributions by internally tracking ozone formed from emissions in each source area. In raw form, the source apportionment technique produces a ''ppb'' contribution from each source area to hourly ozone in each receptor grid cell. The individual hourly ''ppb'' contributions were treated in the way described below to calculate 1-hour and 8-hour values for the four metrics. The approach was based on recommendations to EPA by Environ, the developers of CAMx. For 1-hour concentrations the metrics are calculated based on contributions to all hourly predictions >=125 ppb. For 8-hour concentrations, the metrics are calculated based on the contribution to every 8-hour period in a day with an average concentration >=85 ppb. In order to provide a link to the way 1-hour and 8-hour concentrations were treated for the zero-out runs, EPA also calculated the CAMx metrics for 1-hour daily maximum values >=125 ppb and 8-hour daily maximum values >=85 ppb.[43] The full set of results for all of the CAMx metrics is contained in the Air Quality Modeling TSD.

The CAMx Metrics 1 and 2 provide information on the magnitude and frequency of contributions in a form that is similar to UAM–V Metrics 1 and 2.

CAMx Metric 3: Highest Daily Average Contribution. This metric is the highest daily average ozone ''ppb'' contribution from each upwind source area to each downwind nonattainment receptor area over all days modeled in all four episodes. The following example illustrates how this metric is calculated for 1-hour ozone concentrations. Similar procedures are followed for calculating this metric for 8-hour concentrations. First, the hourly ''ppb'' contributions from a particular upwind source area to each nonattainment receptor in a downwind area are summed across all receptors in the downwind area. This total daily contribution is then divided by the number of hours and grid cells>=125 ppb in the downwind area to determine the daily average ''ppb'' contribution. This calculation is performed on a day by day basis for each day in the 4 episodes. After the average contributions are calculated for each day, the highest daily average value across all episodes is selected for analysis. In addition, the highest daily average contribution is expressed as a percent of the downwind area's average ozone >=125 ppb. That is, the highest daily average ''ppb'' contribution is divided by the average of the ozone concentrations >=125 ppb on that day (i.e., the day on which the highest average ppb contribution occurred). For example, if the highest daily average contribution from an upwind State to nonattainment downwind is 15 ppb and the average of the hourly ozone values >=125 ppb on this day in the downwind area is 150 ppb, then the 15 ppb contribution, expressed as a percent, is 10 percent.

CAMx Metric 4: Percent of Total Manmade Ozone Contribution. This metric represents the total contribution from emissions in an upwind State relative to the total ozone for all hours above the NAAQS in the downwind area. This metric, which is referred to as the ''average contribution,'' is calculated for each episode as well as for all four episodes combined. The following example is used to illustrate how this metric is calculated for a single episode for a particular downwind area. In step 1, all predicted Base Case hourly values >=125 ppb in the downwind area are summed over all nonattainment receptors and all days in an episode. In step 2, the ''ppb'' contributions from a source area to this downwind area are summed over all nonattainment receptors in the downwind area and all days in the episode to yield a total ppb contribution. The total contribution calculated in Step 2 is then divided by the total ozone >=125 ppb in the downwind area to produce the fraction of ozone >=125 ppb in the downwind area that is due to emissions from the upwind source area. This fraction is multiplied by 100 to express the result as a percent.

4. Confirmation of States Making a Significant Contribution to Downwind Nonattainment

In the proposal, EPA made findings of significant contribution based on a

[43] As described in the Air Quality Modeling TSD, the metrics calculated using the hourly contributions >= 125 ppb are consistent with the metrics calculated using 1-hour daily maximum contributions >= 125 ppb. Similarly, the metrics calculated using all 8-hour periods >= 85 ppb are consistent with the metrics calculated using 8-hour daily maximum values >= 85 ppb.

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weight-of-evidence approach that included consideration of air quality contributions based on subregional modeling. As discussed in section II.C.2, Summary of Notice of Proposed Rulemaking Weight-of-Evidence Approach, EPA believes that the subregional modeling provides an adequate independent basis for determining which States contribute significantly to downwind nonattainment. The evaluation of the State-by-State modeling confirms the overall findings that were based on the subregional modeling and provides more refined information regarding the impacts of specific upwind States on nonattainment in individual downwind areas. This State-by-State modeling is discussed in more detail below.

a. Analysis Approach. The EPA has analyzed the results of the State-by-State UAM–V zero-out modeling and the State-by-State CAMx source apportionment modeling for each of the 23 jurisdictions for which this modeling is available.[44] Both UAM–V and CAMx modeling results are available for fifteen States (i.e., Alabama, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Michigan, Missouri, North Carolina, Ohio, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin). For an additional eight States (i.e., Connecticut, Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and Rhode Island), CAMx modeling is available. Also, as noted above in Section II.C.3, State-by-State Air Quality Modeling, Connecticut and Rhode Island were combined as a single source area, and Maryland, the District of Columbia, and Delaware were also combined as a single source area. Because the NO_X emissions and/or NO_X emissions density is large in each jurisdiction within both of these combined source areas, EPA believes that the downwind contributions from these combined source areas can be attributed to each jurisdiction within the source area.

For the 1-hour NAAQS, EPA evaluated downwind impacts in two ways using the factors described in Section II.C.3, State-by-State Air Quality Modeling. First, EPA evaluated the contributions from each upwind State to nonattainment in each downwind State. Second, the EPA evaluated the contributions from each upwind State to nonattainment in each downwind 1-hour nonattainment area. In downwind States which only contain a single intrastate nonattainment area (e.g., Atlanta), the results of the downwind State and downwind nonattainment area analyses are the same because the same nonattainment receptors are used in both cases. For the 8-hour NAAQS, EPA evaluated the contributions from upwind States to 8-hour nonattainment in each downwind State.

The EPA used the following process in determining whether a particular upwind State contributes significantly to 1-hour nonattainment in an individual downwind area. First, EPA reviewed the extent of the nonattainment problem in the downwind area using ambient design values and model predictions of future ozone concentrations after the application of (a) 2007 Base Case controls, (b) additional local NO_X reductions, and (c) regional reductions (additional local plus upwind NO_X reductions).[45] As indicated above, EPA determined that each downwind area had a residual nonattainment problem even after implementation of the control measures in the 2007 Base Case.

Second, using the information from CAMx Metric 4[46], EPA reviewed (a) the relative portion of the ozone problem in each downwind area that is due to ''local'' emissions (i.e., emissions from the entire State or States in which the downwind area is located), (b) the total contribution from all upwind emissions (i.e., the sum of the contributions from manmade emissions in all upwind States, combined), and (c) the contribution from manmade emissions in individual upwind States. The local versus upwind contributions for each downwind area are provided in the Air Quality Modeling TSD. The EPA analyzed this information to determine whether upwind emissions are an important part of the downwind areas' nonattainment problem. In general, the data indicate that, although a substantial portion of the 1-hour nonattainment problem in many of the downwind areas is due to local emissions, a substantial portion of the nonattainment problem is also due to emissions from upwind States. In addition, for most upwind-State-to-downwind-area linkages there is no single upwind State that makes up all of the upwind contribution. Rather, the total contribution for all upwind States combined is comprised of individual contributions from a number of upwind States many of which are relatively similar in magnitude such that there is no ''bright line'' which distinguishes between the contributions from most of the individual upwind States.

Third, EPA determined whether each individual upwind State significantly contributes to nonattainment in a particular downwind area using the UAM–V and CAMx metrics to evaluate three aspects, or factors of the contribution.[47] These factors include the magnitude, frequency, and relative amount of the contribution. The specific UAM–V and CAMx metrics which correspond to each of the factors are identified in Table II–2. As indicated in the table, there is at least one metric from each modeling technique that corresponds to each of the three factors.

TABLE II–2.—METRICS ASSOCIATED WITH EACH CONTRIBUTION FACTOR

Factor	UAM–V	CAMx
Magnitude of Contribution	Maximum ''ppb'' contribution (Metric 2)	Maximum ''ppb'' Contribution (Metric 2); and Highest Daily Average Contribution (Metric 3).
Frequency of Contribution	Number and percent of exceedences with contributions in various concentration ranges (Metric 1 and 2)	Number and percent of exceedences with contributions in various concentration ranges (Metric 1 and 2).
Relative Amount of Contribution.	Total ''ppb'' contribution relative to the total ''ppb'' that the downwind area is above the NAAQS (Metric 3); and Total population-weighted ''ppb'' contribution relative to the total population-weighted ''ppb'' that the downwind area is above the NAAQS (Metric 4)	Four-episode average percent contribution from the upwind State to nonattainment in the downwind area (Metric 4); and Highest single-episode average percent contribution from the upwind State to nonattainment in the downwind area (Metric 4).

[44] The approach for dealing with the 15 States in the OTAG domain which were not proposed to make a significant contribution to downwind nonattainment are discussed below in Section II.C.5, States Not Covered by this Rulemaking.

[45] Scenarios (b) and (c) refer to the runs used to assess transport as described in Section IV.

[46] This information represents the average contributions across all four episodes. In addition to the four-episode average contribution, EPA also examined the highest single-episode average contribution from each upwind State to each downwind area.

[47] The factors used to interpret the metrics should not be confused with the multi-factor approach used to identify the amounts of NO_X emissions that contribute signficantly to nonattainment.

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It should be noted that the relative contributions of individual upwind States to a particular downwind area add up to 100 percent for the CAMx 4-episode average percent contribution. However, this is not the case for the CAMx highest single-episode average percent contribution since the value from one upwind State can occur in a different episode than the value from another upwind State for the same downwind area. In addition, it should be noted that UAM–V Metrics 3 and 4 are used in combination to express the total contribution above the NAAQS relative to the total amount that the downwind area is above the NAAQS. The values for each of these metrics also do not add up to 100 percent when considering contributions from multiple upwind States to an individual downwind area.

The EPA compiled the UAM-V and CAMx metrics by downwind area in order to evaluate the contributions to downwind nonattainment. The data on 1-hour and 8-hour contributions were compiled and analyzed separately. The data were reviewed to determine how large of a contribution a particular upwind State makes to nonattainment in each downwind area in terms of the magnitude of the contribution and the relative amount of the total contribution. The data were also examined to determine how frequently the contributions occur.

The first step in evaluating this information was to screen out linkages for which the contributions were very low, as described in the Air Quality Modeling TSD. The finding of significance for linkages that passed the initial screening criteria was based on EPA's technical assessment of the values for the three contribution factors. Each upwind State that had large and/ or frequent contributions to the downwind area, based on these factors, is considered as contributing significantly to nonattainment in the downwind area. The EPA believes that each of the factors provides an independent legitimate measure of contribution. However, there had to be multiple factors that indicate large and/ or frequent contributions in order for the linkage to be significant. In this regard, the finding of a significant contribution for an individual linkage was not based on any single factor.

For many of the individual linkages the factors yield a consistent result (i.e., either large and/or frequent contributions or small and/or infrequent contributions). In some cases, however, not all of the factors are consistent. For upwind-downwind linkages in which some of the factors indicate high and/or frequent contributions while other factors do not, EPA considered the overall number and magnitude of those factors that indicate large and/or frequent contributions compared to those factors that do not. Based on an assessment of all the factors in such cases, EPA determined that the upwind State contributes significantly to nonattainment in the downwind area if on balance the factors indicate large and/or frequent contributions from the upwind State to the downwind area.

The EPA's evaluation of the contributions to 1-hour nonattainment in New York City is presented as an example to illustrate this process. The New York City area, which consists of portions of New York, New Jersey, and Connecticut, is designated as a severe nonattainment area under the 1-hour NAAQS. The ambient 1-hour design value in New York City, based on 1994 through 1996 monitoring data is 144 ppb. During the four OTAG episodes, 39 percent of the days are predicted to have 1-hour exceedences in 2007 after the implementation of all CAA controls and Federal measures.[48] Moreover, EPA's air quality modeling of the benefits of regional NO_X strategies, as described in Section IV, Air Quality Assessment, indicates that there would still be exceedences of the 1-hour NAAQS remaining in New York City even with eliminating the significant amounts of emissions required by this NO_X SIP Call.

In the assessment of contributions to New York City, EPA examined the local versus upwind contributions to 1-hour nonattainment in this area, as shown in Table II–3. Local emissions in the New York City nonattainment area are spread among numerous stationary sources, area sources, highway sources, and nonroad sources, each of which contributes only a very small, indeed sometimes immeasurable, amount to New York City's ozone nonattainment problem. Combined, these emissions result in approximately 55 percent of the New York City area's ozone problem. Emissions from States upwind of New York, New Jersey, and Connecticut, on average across all four episodes, contribute 45 percent of the nonattainment problem in New York City is due to. However, no single State stands out as contributing most of the total upwind contribution. The biggest single contributor is Pennsylvania (18 percent) followed by Maryland/ Washington, DC/Delaware (5 percent). The total contribution from all Northeast States is 23 percent. A similar amount (22 percent) of the total contribution is due to emissions in those States outside the Northeast. The data in Table II–3 indicate that 19 percent of the 22 percent is fairly evenly divided among ten States, whose contributions range from 1 percent (6 States) to 4 percent (Ohio and Virginia). The remaining 3 percent (i.e., 19 percent vs 22 percent) is from States that each contribute less than 1 percent, on average. The highest single-episode contributions from States upwind of the Northeast range from 1 percent (Tennessee) to 8 percent (Virginia). In general, the contribution data in Table II–3 indicate that a substantial amount of New York City's nonattainment problem is due to the collective contribution from emissions in a number of upwind States both within and outside the northeast. That these upwind contributions are a meaningful part of New York City's nonattainment problem is particularly evident in light of the fact that the contribution to the problem made by New York City itself is comprised of the collective contribution of numerous sources.

TABLE II–3.—PERCENT CONTRIBUTION FROM UPWIND STATES TO 1-HOUR NONATTAINMENT IN NEW YORK CITY [1]

Downwind area: New York City	Percent of total manmade emissions over 4 episodes	Highest single-episode percent contribution [2]
Amount due to "Local" Emissions [3]	55	[4]NA
Total Amount from all "Upwind" States	45	NA
Contributions from Individual Upwind States		
PA	18	19
MD/DC/DE	5	6

[48] This is further described in the Air Quality Modeling TSD.

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TABLE II–3.—PERCENT CONTRIBUTION FROM UPWIND STATES TO 1-HOUR NONATTAINMENT IN NEW YORK CITY [1]—Continued

Downwind area: New York City	Percent of total manmade emissions over 4 episodes	Highest single-episode percent contribution [2]
OH	4	6
VA	4	8
WV	3	7
IL	2	3
IN	1	2
KY	1	3
MI	1	4
MO	1	2
NC	1	2
TN	1	1
Total Amount from All Other States, combined	3	NA.

[1] These values are based on CAMx Metric 3 calculated across all 4 episodes.
[2] These values are based on CAMx Metric 3 calculated for each episode individually. These values do not add up to 100 percent.
[3] 3. Total contribution from the State(s) in which the Nonattainment area is located.
[4] 4. Not applicable.

The extent of New York City's nonattainment problem and the nature of the contributions from upwind States were considered in determining whether the values of the metrics indicate large and/or frequent contributions for individual upwind States. Specifically, additional controls beyond the local and upwind NO_X reductions which are part of the regional NO_X strategy may be needed to solve New York City's 1-hour nonattainment problem. Also, the total contribution from all upwind States is large and there is no single State or small number of States which comprise this total upwind portion. In this regard, the contributions to New York City from some States may not appear to be individually ''high'' amounts. However, (as described below) these contributions, when considered together with the contributions from other States (i.e., the collective contribution) produce a large total contribution to nonattainment in New York City.

The EPA evaluated the magnitude, frequency, and relative amount of contribution from emissions in individual upwind States to determine which States contribute significantly to 1-hour nonattainment in New York City. The UAM–V and CAMx metrics which quantify each upwind State's contribution to New York City for each of the three factors are provided in the Air Quality Modeling TSD and described below. Examination of the values for these metrics indicates that the upwind States can be divided into three general groups, based on the magnitude, frequency, and relative amount of contribution. The first group contains those upwind States for which the UAM–V and CAMx metrics all clearly indicate a significant contribution to 1-hour nonattainment in New York City. The second group contains those States for which the CAMx and UAM–V metrics are not quite as consistent, but overall the metrics indicate a significant contribution to 1-hour nonattainment in New York City. [49] The third group contains those States for which the CAMx and UAM–V metrics clearly indicate that the impacts do not make a significant contribution to New York City.

Group 1 Upwind States:

The CAMx and UAM–V metrics all clearly indicate that emissions from Maryland/Washington, DC/Delaware, Ohio, Pennsylvania, Virginia, and West Virginia make large and/or frequent contributions to 1-hour nonattainment in New York City. For Pennsylvania the magnitude of contribution, as indicated by the highest daily average contribution (CAMx Metric 3), is 25 ppb and the relative amount of contribution is 18 percent (CAMx Metric 4). For the other upwind areas, the magnitude of the contributions range from 9 ppb to 15 ppb (CAMx Metric 3, highest daily average contributions) with contributions in the range of 5 ppb to 10 ppb—from Ohio, Virginia, and West Virginia (UAM–V Metric 2, maximum ''ppb'' contribution). In terms of the frequency of the contribution, 7 percent to 11 percent of the total number of grid-hours >=125 ppb in New York City receive contributions of 10 ppb from each of these States (CAMx Metric 1 and 2). Also, the relative amounts of the contribution are in the range of 6 percent to 8 percent (CAMx Metric 4, highest single-episode average percent contribution) and the total contribution from each of three States (i.e., Ohio, Virginia, and West Virginia) is large compared to the total amount of nonattainment, ranging from 8 percent to 11 percent (UAM–V Metric 3).

Group 2 Upwind States:

The CAMx and UAM–V metrics are somewhat less consistent on the extent of contributions from each of 5 States: Kentucky, Illinois, Indiana, Michigan, and North Carolina. None of the metrics for either model indicate extremely low or extremely high contributions. Rather, for these States most of the metrics indicate relatively high contributions while a few metrics indicate relatively low contributions. The rationale used by EPA for evaluating the contributions from these States involved comparing and contrasting each piece of data for these States on an individual ''upwind State-by-upwind State'' basis and as a group (i.e., for all 5 States, together) in order to weigh the relative magnitude and frequency of the contributions for making a determination of significance. UAM–V Metrics—For each of these 5 States the ''weakest'' factor is the magnitude contribution (UAM–V Metric 2) in that the highest contributions are in the range of 2 to 5 ppb. The other UAM–V Metrics, however, indicate that the contributions from each State are of a larger frequency and relative amount. Specifically, four of these States (Kentucky, Indiana, Illinois, and

[49] For New York City, each of the ''Group 2'' States were found to make a significant contribution. However, this was not the case for all of the Group 2 linkages in other nonattainment areas. For example, the contribution from Kentucky to Philadelphia and the contribution from Tennessee to Baltimore were Group 2 situations in which EPA determined that the contributions were not significant.

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Michigan) each contribute 2 to 5 ppb to as many as 3 percent to 4 percent of the exceedences in New York City (UAM–V Metrics 1 and 2). While North Carolina contributes to somewhat fewer exceedences (2 percent), this slight weakness is out-weighed by the relative amount of contribution (UAM–V Metrics 3 and 4) which indicates that the total contribution from North Carolina alone is equivalent to 3 percent of the total ''ppb'' >=125 ppb and 4 percent of the population-weighted ''ppb'' >=125 ppb in New York City. For Indiana, Illinois, and Michigan the relative amount of contribution (UAM– V Metrics 3 and 4) is also relatively high and ranges from 3 percent to 5 percent. The relative amount of contribution from Kentucky is somewhat weaker at 2 percent.

CAMx Metrics—For Illinois, all of the CAMx metrics indicate relatively large and/or frequent contributions, as described below. For Kentucky, Indiana, Michigan, and North Carolina the magnitude of contribution is large, as indicated by the maximum contribution which ranges from 6 ppb (Indiana) to 11 ppb (North Carolina). Also, the highest daily average contribution from Kentucky, Michigan, and North Carolina are all in the range of 5 ppb to 7 ppb. In terms of the frequency of contribution, Indiana and North Carolina contribute in the range of 5 ppb to 10 ppb to 3 percent and 6 percent of the exceedences, respectively, in New York City. For Kentucky, Indiana, Michigan, and North Carolina the relative amounts of contribution is somewhat mixed in that the 4-episode average percent contribution is only 1 percent, but the highest single-episode average percent contributions are higher at 2 percent from both Indiana and North Carolina, 3 percent from Kentucky, and 4 percent from Michigan (CAMx Metric 4).

Overall contributions considering UAM–V and CAMx Metrics—Considering the CAMx and UAM–V metrics, as described below, the majority of the contribution factors indicate that, overall, each of the Group 2 States contributes significantly to 1-hour nonattainment in New York City.

Kentucky—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution from CAMx is 9 ppb (CAMx Metric 2) and highest daily average contribution is 7 ppb (CAMx Metric 3);
—Frequency of Contribution: 4 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2); and
—Relative Amount of Contribution: the highest single-episode average contribution is 3 percent (CAMx Metric 4).

Metrics indicating relatively low and/ or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb; and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Indiana—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum ''ppb'' contribution is 6 ppb (CAMx Metric 2);
—Frequency of Contribution: 4 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2) ; and
—Relative Amount of Contribution: the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment (UAM–V Metric 3).

Metrics indicating relatively low and/ or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from is 2 ppb (UAM–V Metric 2); and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Illinois—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb;
—Frequency of Contribution: 3 percent of the exceedences receive contributions of more than 2 ppb; and
—Relative Amount of Contribution: the highest single-episode average contribution is 3 percent (CAMx Metric 4); the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment.

Metrics indicating relatively low and/ or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb.

Michigan—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 7 ppb (CAMx Metric 2); the highest daily average contribution is 5 ppb (CAMx Metric 3);
—Frequency of Contribution: 3 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2); and
—Relative Amount of Contribution: the highest single-episode average contribution is 4 percent (CAMx Metric 4); the total ''ppb'' contribution is equivalent to 3 percent of the total amount of nonattainment.

Metrics indicating relatively low and/ or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb
—Frequency of Contribution: 1 percent of the exceedences receive contributions of 5 ppb or more (CAMx Metrics 1 and 2); and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

North Carolina—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 11 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3);
—Frequency of Contribution: 6 percent of exceedences receive contributions of 5 ppb or more (CAMx Metrics 1 and 2); and
—Relative Amount of Contribution: the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment.

Metrics indicating relatively low and/ or infrequent contributions:

—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Group 3 Upwind States: The CAMx and UAM–V metrics clearly indicate that the emissions from the following States do not make large and/or frequent contributions to 1-hour nonattainment in New York City: Alabama, Georgia, Massachusetts, Missouri, South Carolina, Tennessee, and Wisconsin. The rationale for this conclusion is as follows:

—Magnitude of Contribution: all of these upwind States individually contribute less than 2 ppb to 1-hour daily maximum exceedences in New York City (UAM–V Metric 2); the highest daily average contribution was 1 ppb or less from Alabama, Georgia, and Massachusetts, and 2 ppb from South Carolina, Tennessee, and Wisconsin (CAMx Metric 3); and

—Relative Amount of Contribution: the 4-episode average contributions from Alabama, Georgia, Massachusetts, South Carolina, and Wisconsin are less than 1 percent (CAMx Metric 4); the total contributions from Missouri and Tennessee are each equivalent to 1 percent of the total amount of nonattainment in New York City (UAM–V Metric 3).

Based on the preceding evaluation, EPA believes that emissions in each of the following twelve jurisdictions contribute significantly to 1-hour nonattainment in the New York City nonattainment area: the District of Columbia, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia.

b. States Which Contain Sources That Significantly Contribute to Downwind Nonattainment. The results of EPA's assessment of the State-by-State UAM–V and CAMx modeling confirms the findings based on subregional modeling that the 23 jurisdictions contribute large and/or frequent amounts to downwind nonattainment under both the 1-hour and 8-hour NAAQS and forms an independent basis for those findings. The specific upwind States which significantly contribute to nonattainment in specific downwind States are listed in Tables II–4 and II–5 for the 1-hour NAAQS and Table II–6 and Table II–7 for the 8-hour NAAQS. The information on the 1-hour contribution linkages are presented by upwind State in Table II–4 and by downwind State in Table II–5. In Table II–4 the upwind States are each listed in the first column and the downwind States to which each upwind State contributes significantly are listed in the second column. In Table II–5, the same information is presented by downwind State. In this table, each downwind State is listed in the first column and the upwind States that contribute to that downwind State are listed in the second column. The 8-hour contribution linkages are presented by upwind State in Table II–6 and by downwind State in Table II–7.

TABLE II–4.—DOWNWIND STATES FOR WHICH UPWIND STATES CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT [1]

Upwind state	Downwind states
Alabama	GA, IL*, IN*, MI*, TN, WI*.
Connecticut	ME, MA, NH.
Delaware	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
District of Columbia	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
Georgia	AL, TN.
Illinois	CT*, IN, MD, NJ*, NY, MI, MO, WI*.
Indiana	CT*, DE*, DC*, IL*, KY, MD, NJ*, NY, MI, OH, VA*, WI*.
Kentucky	AL, CT*, DC*, GA, IL*, IN, MD, MI*, NJ, NY, MO, OH, VA, WI*.
Maryland	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
Massachusetts	ME, NH.
Michigan	CT, DC*, MD, NJ, NY, VA*.
Missouri	IL, IN, MI, WI*.
New Jersey	CT, ME, MA, NH, NY, PA, RI.
New York	CT, ME, MA, NH, NJ, RI.
North Carolina	CT*, DC*, GA, KY, MD, NJ, NY, OH, PA, VA*.
Ohio	CT, DE, DC*, KY, MD, MA, NH*, NJ, NY, PA, RI, VA.
Pennsylvania	CT, DE, DC, ME, MD, MA, NH, NJ, NY, RI, VA.
Rhode Island	ME, MA, NH.
South Carolina	AL, GA, TN.
Tennessee	AL, GA, IL*, IN, KY, MI*, OH, WI*.
Virginia	CT, DE, DC, KY*, MD, MA, NH*, NJ, NY, PA, RI.
West Virginia	CT, DE, DC, MD, MA, NJ, NY, PA, RI, VA.
Wisconsin	IL*, IN*, MI* .

[1] States marked with an asterisk (*) are included because they are part of an interstate nonattainment area that receives a contribution from the upwind State. New Hampshire is included because it is part of the combined Boston/Portsmouth area; Connecticut and New Jersey are included because they are part of the New York City area; Kentucky is included because it is part of the Cincinnati area; Delaware is included because it is part of the Philadelphia area; Illinois is included because it is part of the St. Louis area; Illinois, Indiana, Michigan, and Wisconsin are included because they are part of the Lake Michigan area; and Maryland, Virginia, and the District of Columbia are included because they are part of the Washington, DC area.

TABLE II–5.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT IN DOWNWIND STATES [1]

Downwind state	Upwind states
Alabama	GA, KY, SC, TN.
Connecticut	DE, DC, IL*, IN*, KY*, MD, MI*, NJ, NY, NC*, OH, PA, VA, WV.
Delaware	IN*, OH, PA, VA, WV.
District of Columbia	IN*, KY*, MI*, NC*, OH*, PA, VA, WV.
Georgia	AL, KY, NC, SC, TN.
Illinois	AL*, IN*, KY*, MO, TN*, WI*.
Indiana	AL*, IL, KY, MO, TN, WI*.
Kentucky	IN, NC, OH, TN, VA*.
Maine	CT, DE, DC, MD, MA, NJ, NY, PA, RI.
Maryland	IL, IN, KY, MI, NC, OH, PA, VA, WV.
Massachusetts	CT, DE, DC, MD, NJ, NY, OH, PA, RI, VA, WV.
Michigan	AL*, IL, IN, KY*, MO, TN*, WI*.
Missouri	IL, KY.

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TABLE II–5.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT IN DOWNWIND STATES [1]—Continued

Downwind state	Upwind states
New Hampshire	CT, DC*, DE*, MD*, MA, NJ, NY, OH*, PA, RI, VA*.
New Jersey	DE, DC, IL*, IN*, KY, MD, MI, NY, NC, OH, PA, VA, WV.
New York	DE, DC, IL, IN, KY, MD, MI, NJ, NC, OH, PA, VA, WV.
Ohio	IN, KY, TN, NC.
Pennsylvania	DE, DC, MD, NJ, NC, OH, VA, WV.
Rhode Island	DE, DC, MD, NJ, NY, OH, PA, VA, WV.
Tennessee	AL, GA, SC.
Virginia	DE, DC, IN*, KY, MD, MI*, NC*, OH, PA, WV.
Wisconsin	AL*, IL*, IN*, KY*, MO*, TN* .

[1] Upwind States marked with an asterisk (*) are considered to significantly contribute to the downwind State because they contribute to an interstate nonattainment area that includes part of the downwind State. New Hampshire is included in the Boston/Portsmouth area; Connecticut and New Jersey are included in the New York City area; Kentucky is included in the Cincinnati area; Delaware is included in the Philadelphia area; Illinois is included in the St. Louis area; Illinois, Indiana, Michigan, and Wisconsin are included in the Lake Michigan area; and Maryland and Virginia are included in the Washington, DC area.

TABLE II–6.—DOWNWIND STATES TO WHICH SOURCES IN UPWIND STATES CONTRIBUTE SIGNIFICANTLY FOR THE 8-HOUR STANDARD

Upwind state	Downwind states
Alabama	GA, IL, IN, KY, MI, MO, NC, OH, PA, SC, TN, VA.
Connecticut	ME, MA, NH, RI.
Delaware	CT, ME, MA, NH, NJ, NY, PA, RI, VA.
District of Columbia	CT, ME, MD, MA, NH, NJ, NY, PA, RI, VA.
Georgia	AL, IL, IN, KY, MI, MO, NC, SC, TN, VA.
Illinois	AL, CT, DC, DE, IN, KY, MD, MI, MO, NJ, NY, OH, PA, RI, TN, WV, WI.
Indiana	DE, IL, KY, MD, MI, MO, NJ, NY, OH, PA, TN, VA, WV, WI.
Kentucky	AL, DC, DE, GA, IL, IN, MD, MI, MO, NJ, NY, NC, OH, PA, SC, TN, VA, WV, WI.
Maryland	CT, DE, DC, ME, MA, NH, NJ, NY, PA, RI, VA.
Massachusetts	ME, NH
Michigan	CT, DC, DE, MD, MA, NJ, NY, OH, PA, WV.
Missouri	IL, IN, KY, MI, OH, PA, TN, WI.
New Jersey	CT, ME, MA, NH, NY, PA, RI.
New York	CT, ME, MA, NH, NJ, PA, RI.
North Carolina	AL, CT, DE, GA, IN, KY, ME, MD, MA, NJ, NY, OH, PA, RI, SC, TN, VA, WV.
Ohio	CT, DC, DE, IN, KY, MD, MA, MI, NJ, NY, NC, PA, RI, TN, VA, WV.
Pennsylvania	CT, DC, DE, ME, MD, MA, NH, NJ, NY, OH, RI, VA.
Rhode Island	ME, MA, NH.
South Carolina	AL, GA, IN, KY, NC, TN, VA.
Tennessee	AL, DC, DE, GA, IL, IN, KY, MD, MI, MO, NC, OH, PA, SC, VA, WV, WI.
Virginia	CT, DE, DC, ME, MD, MA, NJ, NY, NC, OH, PA, RI, SC, WV.
West Virginia	CT, DC, DE, IN, KY, MD, MA, NJ, NY, NC, OH, PA, RI, SC, TN, VA.
Wisconsin	MI.

TABLE II–7.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 8-HOUR NONATTAINMENT IN DOWNWIND STATES.

Downwind state	Upwind states
Alabama	GA, IL, KY, NC, SC, TN.
Connecticut	DE, DC, IL, MD, MI, NJ, NY, NC, OH, PA, VA, WV.
District of Columbia	IL, KY, MD, MI, OH, PA, TN, VA, WV.
Delaware	IL, IN, KY, MI, NC, OH, PA, TN, VA, WV.
Georgia	AL, KY, NC, SC, TN.
Illinois	AL, GA, IN, KY, MO, TN.
Indiana	AL, GA, IL, KY, MO, NC, OH, SC, TN, WV.
Kentucky	AL, GA, IL, IN, MO, NC, OH, SC, TN, WV.
Maine	CT, DE, DC, MD, MA, NJ, NY, NC, PA, RI, VA
Maryland	DC, IL, IN, KY, MI, NC, OH, PA, TN, VA, WV.
Massachusetts	CT, DE, DC, MD, MI, NJ, NY, NC, OH, PA, RI, VA, WV.
Michigan	AL, GA, IL, IN, KY, MO, OH, TN, WI.
Missouri	AL, GA, IL, IN, KY, TN.
New Hampshire	CT, DE, DC, MD, MA, NJ, NY, PA, RI.
New Jersey	DE, DC, IL, IN, KY, MD, MI, NC, NY, OH, PA, VA, WV.
New York	DE, DC, IL, IN, KY, MD, MI, NC, NJ, OH, PA, VA, WV.
North Carolina	AL, GA, KY, OH, SC, TN, VA, WV.
Ohio	AL, IL, IN, KY, MI, MO, NC, PA, TN, VA, WV.
Pennsylvania	AL, DE, DC, IL, IN, KY, MD, MI, MO, NJ, NY, NC, OH, TN, VA, WV.
Rhode Island	CT, DE, DC, IL, MD, NJ, NY, NC, OH, PA, VA, WV.

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TABLE II–7.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 8-HOUR NONATTAINMENT IN DOWNWIND STATES.—Continued

Downwind state	Upwind states
South Carolina	AL, GA, KY, NC, TN, VA, WV.
Tennessee	AL, GA, IL, IN, KY, MO, NC, OH, SC, WV.
Virginia	AL, DE, DC, GA, IN, KY, MD, NC, OH, PA, SC, TN, WV.
West Virginia	IL, IN, KY, MI, NC, OH, TN, VA.
Wisconsin	IL, IN, KY, MO, TN.

c. Examples of Contributions From Upwind States to Downwind Nonattainment. A full discussion of EPA's analysis supporting the determination that specific upwind States contribute significantly to individual downwind States under the 1-hour and 8-hour NAAQS is provided in the Air Quality Modeling TSD. Examples of the types of contributions which link individual upwind States to downwind areas are provided below for the 1-hour NAAQS for the 23 upwind jurisdictions.

—Alabama's Contribution to 1-Hour Nonattainment in Atlanta

Magnitude of Contribution: The maximum contribution is 39 ppb (CAMx Metric 2); the highest daily average contribution is 31 ppb (CAMx Metric 3).

Frequency of Contribution: Alabama contributes at least 10 ppb to 12 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Alabama is equivalent to 14 percent of the total amount >=125 ppb in Atlanta (UAM–V Metric 3); Alabama contributes 8 percent of the total manmade ppb >= 125 ppb in Atlanta (CAMx Metric 4; 4-episode average percent contribution).

—Connecticut/Rhode Island's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 61 ppb (CAMx Metric 2); the highest daily average contribution is 50 ppb (CAMx Metric 3).

Frequency of Contribution: Connecticut/Rhode Island contribute at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Connecticut/Rhode Island contribute 35 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—Georgia's Contribution to 1-Hour Nonattainment in Birmingham

Magnitude of Contribution: The maximum contribution is 51 ppb (CAMx Metric 2); the highest daily average contribution is 24 ppb (CAMx Metric 3).

Frequency of Contribution: Georgia contributes at least 10 ppb to 11 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Georgia is equivalent to 12 percent of the total amount >=125 ppb in Birmingham (UAM–V Metric 3); Georgia contributes 3 percent of the total manmade ppb >= 125 ppb in Birmingham (CAMx Metric 4; 4-episode average percent contribution).

—Illinois's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3).

Frequency of Contribution: Illinois contributes at least 5 ppb to 20 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Illinois is equivalent to 3 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); Illinois contributes 3 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Indiana's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3).

Frequency of Contribution: Indiana contributes at least 5 ppb to 26 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Indiana is equivalent to 4 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Indiana contributes 3 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Kentucky's Contribution to 1–Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 9 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Kentucky contributes at least 5 ppb to 24 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Kentucky is equivalent to 3 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Kentucky contributes 5 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; single highest episode percent contribution).

—Maryland/District of Columbia/Delaware's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 50 ppb (CAMx Metric 2); the highest daily average contribution is 15 ppb (CAMx Metric 3).

Frequency of Contribution: Maryland/District of Columbia/Delaware contribute at least 10 ppb to 14 percent of the 1-hr exceedences and at least 5 ppb to 38 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Maryland/District of Columbia/Delaware contribute 5 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; 4-episode average percent contribution).

—Massachusetts' Contribution to 1-Hour Nonattainment in Portland, ME

Magnitude of Contribution: The maximum contribution is 79 ppb (CAMx Metric 2); the highest daily average contribution is 67 ppb (CAMx Metric 3).

Frequency of Contribution: Massachusetts contributes at least 10 ppb to 100 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Massachusetts is equivalent to 100 percent of the total amount >=125 ppb in Portland, ME

(UAM–V Metric 3); Massachusetts contributes 56 percent of the total manmade ppb >= 125 ppb in Portland, ME (CAMx Metric 4; 4-episode average percent contribution).

—Michigan's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 9 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Michigan contributes at least 5 ppb to 7 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Michigan is equivalent to 5 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Michigan contributes 5 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; single highest episode percent contribution).

—Missouri's Contribution to 1-Hour Nonattainment over Lake Michigan

Magnitude of Contribution: The maximum contribution is 19 ppb (CAMx Metric 2); the highest daily average contribution is 12 ppb (CAMx Metric 3).

Frequency of Contribution: Missouri contributes at least 10 ppb to 66 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Missouri is equivalent to 22 percent of the total amount >=125 ppb over Lake Michigan (UAM–V Metric 3); Missouri contributes 9 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; 4-episode average percent contribution).

—New Jersey's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 30 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: New Jersey contributes at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: New Jersey contributes 16 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—New York's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 25 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: New York contributes at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: New York contributes 18 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—North Carolina's Contribution to 1-Hour Nonattainment in Philadelphia

Magnitude of Contribution: The maximum contribution is 10 ppb (CAMx Metric 2); the highest daily average contribution is 9 ppb (CAMx Metric 3).

Frequency of Contribution: North Carolina contributes at least 2 ppb to 4 percent of the 1-hr exceedences (UAM– V Metrics 1 and 2).

Relative Amount: The total contribution from North Carolina is equivalent to 4 percent of the total amount >=125 ppb in Philadelphia (UAM–V Metric 3); North Carolina contributes 2 percent of the total manmade ppb >= 125 ppb in Philadelphia (CAMx Metric 4; single highest episode percent contribution).

—Ohio's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 13 ppb (CAMx Metric 2); the highest daily average contribution is 12 ppb (CAMx Metric 3).

Frequency of Contribution: Ohio contributes at least 5 ppb to 51 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Ohio is equivalent to 11 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Ohio contributes 4 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; 4-episode average percent contribution).

—Pennsylvania's Contribution to 1-Hour Nonattainment in Greater Connecticut

Magnitude of Contribution: The maximum contribution is 28 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: Pennsylvania contributes at least 10 ppb to 60 percent of the 1-hr exceedences and at least 5 ppb to 98 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Pennsylvania contributes 10 percent of the total manmade ppb >= 125 ppb in Greater Connecticut (CAMx Metric 4; 4-episode average percent contribution).

—South Carolina's Contribution to 1-Hour Nonattainment in Atlanta

Magnitude of Contribution: The maximum contribution is 24 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: South Carolina contributes at least 5 ppb to 6 percent of the 1-hr exceedences (UAM– V Metrics 1 and 2).

Relative Amount: The total contribution from South Carolina is equivalent to 4 percent of the total amount >=125 ppb in Atlanta (UAM–V Metric 3); South Carolina contributes 2 percent of the total manmade ppb >= 125 ppb in Atlanta (CAMx Metric 4; single highest episode percent contribution).

—Tennessee's Contribution to 1–Hour Nonattainment Over Lake Michigan

Magnitude of Contribution: The maximum contribution is 12 ppb (CAMx Metric 2); the highest daily average contribution is 11 ppb (CAMx Metric 3).

Frequency of Contribution: Tennessee contributes at least 5 ppb to 14 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Tennessee is equivalent to 6 percent of the total amount >=125 ppb over Lake Michigan (UAM–V Metric 3); Tennessee contributes 10 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; single highest episode percent contribution).

—Virginia's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 25 ppb (CAMx Metric 2); the highest daily average contribution is 11 ppb (CAMx Metric 3).

Frequency of Contribution: Virginia contributes at least 10 ppb to 11 percent of the 1-hr exceedences and at least 5 ppb to 36 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Virginia is equivalent to 11 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); Virginia contributes 4 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; 4-episode average percent contribution).

—West Virginia's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 14 ppb (CAMx Metric 2); the highest daily average contribution is 10 ppb (CAMx Metric 3).

Frequency of Contribution: West Virginia contributes at least 5 ppb to 9 percent of the 1-hr exceedences and at least 2 ppb to 28 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from West Virginia is equivalent to 9 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); West Virginia contributes 7 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Wisconsin's Contribution to 1–Hour Nonattainment Over Lake Michigan

Magnitude of Contribution: The maximum contribution is 43 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Wisconsin contributes at least 10 ppb to 11 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Wisconsin contributes 4 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; 4-episode average percent contribution).

d. Conclusions From Air Quality Evaluation of Downwind Contributions. As indicated above, EPA is following a multi-step approach for determining whether emissions from an upwind State significantly contribute to nonattainment downwind. The first step involves an air quality evaluation to determine whether the air quality factors, and particularly the extent of the downwind contributions from emissions in the upwind State, indicate that those contributions are large and/or frequent enough to be of concern under the 1-hour and/or 8-hour NAAQS. The second step, as described below, employs a cost-effectiveness analysis to determine which of the upwind emissions may be eliminated through highly cost-effective controls. Any emissions that may be so eliminated are considered to be emissions that significantly contribute to nonattainment downwind. Finally, to confirm that the emissions considered to significantly contribute, taken as a whole, have a meaningful impact on nonattainment in downwind areas, EPA modeled the air quality effects of eliminating that amount of emissions (see Section IV, Air Quality Assessment, below).

The EPA's conclusions from the first step in this process, the air quality evaluation, is that emissions from sources in each of the 23 jurisdictions listed below make a significant contribution to nonattainment downwind for both the 1-hour and 8-hour NAAQS and interfere with maintenance of the 8-hour NAAQS. This determination was based on two independent sets of analyses, each of which EPA believes provides an independent basis for these conclusions. These two independent analyses are (1) subregional modeling using UAM–V, and (2) State-by-State modeling using CAMx and UAM–V. For the subregional modeling, EPA examined the frequency and magnitude of the impacts from each subregion along with State emissions data and other air quality information to evaluate the contributions from upwind States to nonattainment in downwind areas. For the UAM–V and CAMx State-by-State techniques, a number of measures of ozone contribution, or metrics, were used to assess, from several perspectives, the air quality effect of contributions from sources in different upwind States.

The EPA weighed the results of its analysis of these several air quality metrics to determine which upwind States contain sources whose emissions contribute significantly to downwind nonattainment or maintenance problems. By examining the results of several air quality metrics, EPA assured that no one metric determined whether a State contains sources whose emissions contribute to downwind air quality problems. Rather, the determination of whether an upwind State contained sources whose emissions contribute significantly to a downwind nonattainment problem was based on the extent of the contributions reflected by multiple metrics. The EPA concluded that each set of modeling (i.e., subregional and State-by-State) when considered independently under EPA's weight-of-evidence approach provides a sound technical basis for finding that NO_X emissions from sources in the following 23 jurisdictions make a significant contribution to nonattainment of the 1-hour and 8-hour NAAQS in, or interfere with maintenance of the 8-hour NAAQS by, one or more downwind States:

Alabama
Connecticut
Delaware
District of Columbia
Georgia
Illinois
Indiana
Kentucky
Maryland
Massachusetts
Michigan
Missouri
New Jersey
New York
North Carolina
Ohio
Pennsylvania
Rhode Island
South Carolina
Tennessee
Virginia
West Virginia
Wisconsin

The remaining 15 OTAG States not covered by this final rule are discussed below.

5. States Not Covered by This Rulemaking

In Section VI of the NPR, EPA proposed to find that emissions from sources in the following 15 States in the OTAG region do not significantly contribute to downwind nonattainment under the 1-hour or 8-hour ozone NAAQS, or interfere with maintenance under the 8-hour NAAQS: Arkansas, Florida, Iowa, Kansas, Louisiana, Maine, Minnesota, Mississippi, North Dakota, Nebraska, New Hampshire, Oklahoma, South Dakota, Texas, Vermont (62 FR 60369). The EPA received comments on this section of the NPR and has recently conducted some additional CAMx analyses.[50] The CAMx modeling suggested that further analysis using UAM–V State-by-State modeling would be warranted in order to have a set of information comparable to that for other States that are subject to this rule. In today's rulemaking, EPA is taking no action on whether emissions from sources in these 15 States do or do not contribute significantly to downwind nonattainment, or interfere with maintenance downwind, under either NAAQS. Thus, by today's rulemaking, EPA is not requiring these 15 States to submit SIP revisions providing for NO_X emissions controls to meet a statewide NO_X emissions budget; nor is EPA determining that these States will not be required to make these SIP submissions in the future. The EPA is continuing to review available information on the downwind impacts of these States, including comments submitted on the NPR. In addition, EPA plans to conduct State-by-State modeling to determine whether a SIP revision under section 110(a)(2)(D)(i)(I) should be required from any of these States in the future.

[50] See ''Notice of Availability'' 63 FR 45032 (August 24, 1998).

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The EPA intends to begin this modeling in the fall of 1998.

As discussed in the NPR (62 FR 60318 at 60370), EPA reiterates that these 15 States may need to cooperate and coordinate SIP development activities with other States that are subject to today's action. Also, States with interstate nonattainment areas for the 1-hour standard and/or the new 8-hour standard should cooperate in reducing emissions to mitigate local-scale interstate transport problems (e.g., transport from one State in a multi-state urban nonattainment area to another State in that area) to provide for attainment in the nonattainment area as a whole. The EPA encourages the 15 States to conduct additional analyses on ozone transport recommended by the OTAG Policy Group, which indicated that these States, ''* * * will, in cooperation with EPA, periodically review their emissions, and the impact of increases, on downwind nonattainment areas and, as appropriate, take steps necessary to reduce such impacts including appropriate control measures.'' [51]

Comment: A number of commenters supported the proposal to exclude the proposed States, either in general or for specific States. Others opposed the proposal in general, or for specific States.

Response: Because EPA is taking no action on the 15 States at this time, EPA will not respond to comments concerning these States at this time. As discussed above, EPA intends to continue to review ambient air quality data, air quality modeling results, and other technical information on the downwind contribution from all States not found to be significant contributors in today's action.

Comment: Several commenters stated that if EPA revisits which States should be included in the rulemaking, EPA must reopen the public comment period.

Response: The EPA agrees. Because today's action does not propose a change from the NPR concerning which States should be covered, no new comment period is needed at this time. As EPA noted in the NPR, if results from additional modeling and technical analyses indicate that States other than the 22 States (and the District of Columbia) that are the subject of today's action should be required to submit a SIP revision under section 110(a)(2)(D)(i)(I), EPA will publish a new NPR as to any such States and provide an additional comment period.

[51] OTAG Recommendation: Utility NO_X Controls, approved by the Policy Group, June 3, 1997.

As also stated in the NPR, in 2007, EPA will reassess transport in the full OTAG region to evaluate the effectiveness of the regional NO_X measures and the need, if any, for additional regional controls.

D. Cost Effectiveness of Emissions Reductions

As discussed above, in today's action, EPA considers control costs in determining whether, and the extent to which, upwind emissions contribute significantly to nonattainment, or interfere with maintenance downwind. The EPA considers cost factors in conjunction with other factors generally related to levels of emissions.

1. Sources Included In the Cost-Effectiveness Determination

This subsection describes the rationale used to determine the cost effectiveness of emissions reductions measures. The EPA evaluates the relative costs of the available control measures using average cost effectiveness, measured as dollars per ton of NO_X reduced relative to a baseline, to identify those emissions reductions that are ''highly cost-effective.'' In performing this evaluation, EPA considers the cost savings of a regionwide NO_X emissions trading system for large electricity generating boilers and turbines (i.e., boilers and turbines serving a generator larger than 25 MWe). As described in this section, EPA has determined that these emissions reductions are highly cost effective on a regionwide basis.

To assure equity among the various source categories and the industries they represent, EPA considered the cost effectiveness of controls for each source category separately throughout the SIP call region. Sources are combined into a common source category if they serve the same general industry (e.g., boilers and turbines that are used by the electricity generation industry are combined in the same category). In general, this means that the sources in the same source category share the same six-digit source code classification (SCC). One exception is in the case of boilers and turbines which are combined and then separated into (1) a category of boilers and turbines serving generators that produce electricity for sale to the grid; or (2) a category of boilers and turbines that exclusively generate steam and/or mechanical work (e.g., provide energy to an industrial pump), or produce electricity primarily for internal use and not for sale. The EPA believes that this categorization better reflects the industrial sectors served.

For each source category, the required emission levels (in tons per ozone season) were determined based on the application of NO_X controls that achieve the greatest feasible emissions reduction while still falling within a cost-per-ton-reduced range that EPA considers to be highly cost-effective (hereinafter also referred to as ''highly cost-effective'' measures). Marginal or incremental costs of control are additional cost-effective measures that may provide important information about alternatives. In particular, incremental cost-effectiveness helps to identify whether a more stringent control option imposes much higher costs relative to the average cost per ton for further control. The use of an average cost-effectiveness measure may not fully reveal costly incremental requirements where control options achieve large reductions in emissions (relative to the baseline).

In this rulemaking, EPA has chosen to focus on an average cost-effectiveness measure in identifying highly cost-effective control options for several reasons. Since EPA's determination for the core group of sources is based on the adoption of a broad-based trading program, average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs. In addition, average cost-effectiveness estimates are readily available for other recently adopted NO_X control measures.

The EPA examined a representative sample of potentially available controls. NO_X controls for this rulemaking were considered highly cost-effective for the purposes of reducing ozone transport to the extent they achieve the greatest feasible emissions reduction but still cost no more than $2,000 per ton of ozone season NO_X emissions removed (in 1990 dollars), on average, for each source category. The discussion below further describes the basis for this cost amount and the techniques used for each category. Many may consider certain controls that cost more than $2,000 per ton of NO_X reduced to be reasonably cost-effective in reducing ozone transport or in achieving attainment with the ozone NAAQS in specific nonattainment areas; however, EPA has determined to focus today's rulemaking on only highly cost-effective reductions. In the future, as EPA continues to consider the impact of ozone transport and the most effective ways to assure downwind attainment, EPA may reconsider whether State NO_X budget levels should be lowered to reflect application of additional controls

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that, although more expensive, are nevertheless cost-effective. In addition, as discussed below, in determining whether to assume reductions from source categories with only a few sources or relatively small emissions, EPA considered administrative efficiency in developing conclusions about whether to assume emissions reductions for these sources.

In determining the cost of NO_X reductions by large electricity generating units (EGUs), EPA assumed an emissions trading system. As discussed in Section IV below, EPA evaluated and compared the likely air quality impacts of this rulemaking with and without a regionwide NO_X emissions trading system for electricity generating sources. This analysis shows that a regionwide trading program causes no significant adverse air quality impacts. Because such a program would result in significant cost savings, EPA's cost-effectiveness determination for large electricity generating boilers and turbines assumes that each State will adopt the lowest cost approach, i.e., the States will elect to include these sources in a regionwide NO_X emissions trading program. However, States retain the option of choosing other, perhaps more expensive, approaches to achieving the necessary reductions. For non-EGU sources in the core group of the trading program, EPA used a least cost method which is equivalent to an assumption of an intrastate trading program. Inclusion of these sources in a regionwide trading program would provide further cost savings. For other source categories for which EPA identified highly cost-effective controls (i.e., internal combustion engines and cement manufacturing), EPA assumed source-specific controls. However, a State may choose to include such categories in the trading program and realize further cost savings.

For the purposes of this rulemaking, EPA considers the following sizes of point sources to be large: (1) electricity generating boilers and turbines serving a generator greater than 25 MWe; or (2) other point sources with a heat input greater than 250 mmBtu/hr or which emit more than one ton of NO_X per average summer day.

In the NPR, EPA based the cost-effectiveness determination on NO_X emissions controls that are available and of comparable cost to other recently undertaken or planned NO_X measures. Table 1 provides a reference list of measures that EPA and States have recently undertaken to reduce NO_X and their average annual costs per ton of NO_X reduced. Most of these measures fall below $2,000 per ton. With few exceptions, the average cost-effectiveness of these measures is representative of the average cost-effectiveness of the types of controls EPA and States have needed to adopt most recently because their previous planning efforts have already taken advantage of opportunities for even cheaper controls. The EPA believes that the cost-effectiveness of measures that EPA or States have adopted, or proposed to adopt, forms a good reference point for determining which of the available additional NO_X control measures can most easily be implemented by upwind States whose emissions impact downwind nonattainment problems.

TABLE 1.—AVERAGE COST-EFFECTIVENESS OF NO_X CONTROL MEASURES RECENTLY UNDERTAKEN

[1990 dollars]

Control measure	Cost per ton of NO_X Removed
NO_X RACT	150–1,300
Phase II Reformulated Gasoline	[52] 4,100
State Implementation of the Ozone Transport Commission Memorandum of Understanding	950–1,600
New Source Performance Standards for Fossil Steam Electric Generation Units	1,290
New Source Performance Standards for Industrial Boilers	1,790

[52] Average cost representing the midpoint of $2,180 to $6,000 per ton. This cost represents the projected additional cost of complying with the Phase II RFG NO_X standards, beyond the cost of complying with the other standards for Phase II RFG.

The Federal Phase II RFG costs presented in Table 1 are not strictly comparable to the other costs cited in the table. Federal Phase II RFG will provide large VOC reductions in addition to NO_X reductions. Federal RFG is required in nine cities with the nation's worst ozone nonattainment problems; other nonattainment areas have chosen to opt into the program as part of their attainment strategy. The mandated areas and those areas in the OTAG region that have chosen to opt into the program are areas where significant local reductions in ozone precursors are needed; such areas may value RFG's NO_X and VOC reductions differently for their local ozone benefits than they would value NO_X reductions from RFG or other programs for ozone transport benefits.

Commenters on the proposal generally agreed with basing the cost-effectiveness determination on the cost effectiveness of other recently undertaken measures. Therefore, EPA has considered controls with an average cost-effectiveness less than $2,000 per ton of NO_X removed to be highly cost effective and has calculated the amounts of emissions that States must prohibit based on application of these controls. Some commenters believed that a more appropriate measure of cost effectiveness was incremental—instead of average—dollars per ton of NO_X removed. Other commenters believed that a more appropriate measure was dollars per ppb of ozone removed from a nonattainment area. The EPA continues to depend on regionwide average dollars per ton of NO_X removed when evaluating what control measures are highly cost-effective for the purposes of this rulemaking.

Table 2 summarizes the control options investigated for each source category and the resulting average, regionwide cost effectiveness.

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TABLE 2.—AVERAGE COST EFFECTIVENESS OF OPTIONS ANALYZED [53]

[1990 dollars in 2007]

Source category			
	Average Cost-effectiveness ($/ozone season ton) for each control option		
Boilers and Turbines Generating Electricity	0.20 lb/mmBtu $1,263	0.15 lb/mmBtu $1,468	0.12 lb/mmBtu. $1,760.
Boilers and Turbines not Generating Electricity	50% reduction $1,235	60% reduction $1,467	70% reduction. $2,140.
Other Stationary Sources [54]	$3,000/ton maximum per source.	$4,000/ton maximum per source.	$5,000/ton maximum per source.
Cement Manufacturing	$1,458	$1,458	$1,458
Glass Manufacturing	$2,020	$2,339	$4,758.
Incinerators	$2,118	$2,118	$2,118.
Internal Combustion Engines	$1,213	$1,213	$1,215.
Process Heaters	$2,860	$2,896	$2,896.

[53] The cost-effectiveness values in Table 2 are regionwide averages. The cost-effectiveness values represent reductions beyond those required by Title IV or Title I RACT, where applicable.

[54] For cement manufacturing, incinerators, internal combustion engines and process heaters, the table indicates that the same control technology (at the same cost) would be selected whether the cost ceiling for each source is $3,000, $4,000, or $5,000 per ton; thus the average cost-effectiveness number for these source categories is the same in each column. For glass manufacturing, the table indicates that additional emissions reductions would be obtained from more effective and more costly control technologies as the cost ceiling increase.

The following discussion explains the controls determined by EPA to be highly cost-effective for each source category.

The EPA has analyzed the implications of each State limiting trading within its borders compared to entering into a common trading program with all other States, provided that States choose to control EGUs at an average level of 0.15 lb/mmBtu. In the case of intrastate trading, EPA found that the average cost per ton of the resulting ozone season NO_X reduction was about $1,499 per ton. This result from the IPM model was for all the States together considering changes in dispatch and other aspects of the future operation of the nation's power system. Individual State results were not provided by the model. As explained below, EPA expects that individual State cost per ton results are likely to be fairly close to this collective result.

For a regionwide budget based on 0.15 lb/mmBtu, EPA's analyses suggest that whether (1) there were individual State trading programs, or (2) a single regionwide trading program, all States experienced a substantial reduction in summer NO_X emissions from Base Case emissions levels. For this to occur, there have to be similar opportunities throughout the SIP call region for highly cost-effective reductions to occur at EGUs. If this were not true, EPA would have found, in the case where there is a single trading program across the entire SIP call region, that some States reduce a much greater share of their NO_X emissions than other States do. The fact that there are similar opportunities for NO_X reductions in each of the States indicates that if there were individual State trading programs in place they would each generally have an average cost effectiveness for reducing ozone season NO_X emissions that is fairly close to the cost effectiveness of trading programs in other States. Therefore, each State is generally likely to have an average cost effectiveness of about $1,550 per ton, the amount we found in the results of the IPM model run for a scenario where each State ran its own trading program.

a. Electricity Generating Boilers and Turbines. For EGUs larger than 25 MWe, the control level was determined by applying a uniform NO_X emissions rate regionwide. The cost-effectiveness for each control level was determined using the IPM. Details regarding the methodologies used can be found in the Regulatory Impact Analysis of this rulemaking. Table 2 summarizes the control levels and resulting cost-effectiveness of three options analyzed.

A regionwide level of 0.20 lb/mmBtu was rejected because though it resulted in an average cost effectiveness of less than $2,000 per ton, the air quality benefits were less than those for the 0.15 lb/mmBtu level which was also less than $2,000 per ton. The results suggest that a regionwide level of 0.15 lb/mmBtu should be assumed for this source category when calculating the amount of emissions that should be considered significant and therefore prohibited in each covered State. This control level has an average cost-effectiveness of $1,468 per ozone season ton removed. This amount is consistent with the range for cost-effectiveness that EPA has derived from recently adopted (or proposed to be adopted) control measures. As discussed later in this preamble, EPA has determined that EGU sources are fully capable of implementing this level of control by May 1, 2003.

The EPA estimates that a control level based on 0.12 lb/mmBtu, has a cost effectiveness of $1,760 per ozone season ton removed, which is within the upper range of cost effectiveness. This estimate is based on the Agency's best estimates of several key assumptions on the performance of pollution control technologies and electricity generation requirements in the future which the Agency thoroughly researched over the last two years. Given that the cost per ton estimate for 0.12 lb/mmBtu trading is much closer to $2,000 than the 0.15 lb/mmBtu trading, EPA is not as confident about the robustness of the results. Also, although EPA is very comfortable that a 0.15 lb/mmBtu trading program beginning in 2003 will not lead to installation of SCR technology at a level and in a manner that will be difficult to implement or result in reliability problems for electric power generation, the Agency's level of comfort is not as high in considering 0.12 lb/mmBtu-based trading. [55] With a strong need to implement a program by 2003 that is recognized by the States as practical, necessary, and broadly accepted as highly cost effective, the Agency has decided to base the

[55] For reasons explained in Section V., below, EPA has determined that May 1, 2003 is the earliest practicable date for achieving the level of emissions reductions EPA selected, and therefore is the appropriate date for achieving these reductions in light of the CAA's attainment date requirements.

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emissions budgets for EGUs on a 0.15 lb/mmBtu trading level of control.

It should be noted that the cost-effectiveness values for EGUs were calculated using a slightly older version of the final EGU inventory. Changes made to the inventory and growth assumptions resulted in decreasing the final regionwide allowable emission level for EGUs, under the 0.15 option, to 543,825 tons per year from 563,785 tons per year. Reducing the allowable regionwide emissions increased the average cost-effectiveness value of the 0.15 option from $1,468/ton, to $1,503/ ton.

b. Other Stationary Sources. The appropriate cost-effective control level for large non-EGU source categories was determined by evaluating various regulatory alternatives. For industrial boilers and turbines (i.e., boilers and turbines greater than 250 mm/Btu per hour or with NO_X emissions greater than 1 tpd), the control level was determined by applying a uniform percent reduction regionwide in increments of 10 percent. For all other stationary sources, the control level was determined by applying source-category-specific cost-effectiveness thresholds, because trading was not assumed to be readily available for these source categories. Details regarding the methodologies used are in the Regulatory Impact Analysis. Table 2 summarizes the control levels and resulting cost-effectiveness for each option under each category.

Further, for large non-EGUs, the cost-effectiveness determination includes estimates of the additional emissions monitoring costs that sources would incur in order to participate in a trading program. Some non-EGUs already monitor their emissions. In the NPR, EPA had not included monitoring costs in the cost-effectiveness determination because such costs had not been estimated at that time. Since then, EPA has evaluated monitoring system costs. These costs are defined in terms of dollars per ton of NO_X removed so that they can be combined with the cost-effectiveness figures related to control costs. Since monitoring costs do not vary with the level of control, the cost per ton for monitoring varies in accordance with the amount of control being required. For purposes of this analysis, the level of control was assumed to be the level of control used to calculate the budget. Monitoring costs varied from about $150 to $400 per ton of NO_X removed, depending on the type of source category.

The EPA, therefore, determines that: (1) For large non-electricity-generating industrial boilers and turbines, a control level corresponding to 60 percent reduction from baseline levels is highly cost-effective (this percent reduction corresponds to a regionwide control level of about 0.17 lb/mmBtu); and (2) for large internal combustion engines and cement manufacturing sources, a control level corresponding to the application of NO_X reduction technology costing no more than $5,000/ton for each source is, on average, highly cost effective. As indicated in Table 2 and described in detail in the RIA, these control levels are associated with a cost effectiveness of approximately $1,467/ton for boilers and turbines, $1,458/ton for cement manufacturing, and $1,215/ton for internal combustion engines. This results in an average emissions reduction from uncontrolled emissions of 90 percent for internal combustion engines and 30 percent for cement manufacturing sources. The EPA notes that States may include these source categories in the model NO_X budget trading program, further assuring that each source would be able to cost-effectively meet its reduction requirements. The EPA determined that controlling glass manufacturing sources, incinerators, and process heaters was not highly cost-effective because all the options analyzed for these source categories cost more than $2,000 per ton of NO_X removed. Thus, no additional controls are assumed for these sources when determining the significant amounts that must be reduced in each State.

2. Sources Not Included In the Cost-effectiveness Determination

For the following groups of sources, EPA is determining that no additional control measures or levels of control should be assumed in this rulemaking, for the reasons described.

a. Area Sources. In the NPR, EPA noted that control levels for area sources (i.e., sources other than mobile or point sources) could not be determined based on available information concerning applicable control technologies. Comments to the NPR did not identify specific NO_X control technologies that were both technologically feasible and highly cost-effective. Because EPA has no new information on applicable control technologies for area sources, no additional control level is assumed for these sources in this rulemaking. Further discussion concerning area sources can be found in Section III, below, of this preamble.

b. Small Point Sources. For the purposes of this rulemaking, EPA considers the following sizes of point sources to be small: (1) Electricity generating boilers and turbines serving a generator 25 MWe or less, and (2) other point sources with a heat input of 250 mmBtu/hr or less and which emit less than one ton of NO_X per average summer day. In the NPR, EPA stated that the collective emissions from small sources were relatively small (in the context of this rulemaking) and the administrative burden, to the States and regulated entities, of controlling such sources was likely to be considerable. As a result, in the NPR, EPA proposed not to assume reductions from these sources in establishing the State budgets.

Comments to the NPR did not identify specific approaches that would result in significant emission reductions and be administratively efficient in controlling these sources. On the contrary, many comments encouraged EPA to exclude small point sources from any budget calculations for this rulemaking.

Therefore, in today's action, EPA is not assuming additional control levels for these sources. Further discussion concerning small point sources may be found in section III, below, of this preamble.

c. Mobile Sources. In the NPR, EPA noted that it could not identify any additional NO_X controls that States could implement for mobile or nonroad sources beyond those already reflected in the proposed State NO_X budgets that were both technologically feasible and cost-effective, relative to point sources covered by this rule, for the purposes of reducing NO_X. Several commenters stated that the EPA should require States to implement additional reductions for mobile sources. However, these commenters did not identify specific, new, technologically feasible mobile source NO_X controls that were highly cost-effective by the standards of today's action. The EPA has re-examined the availability of mobile source control measures available to States, as discussed in more detail in sections III.D. and III.E. below, and has not identified any such controls that are both technologically feasible and highly cost-effective for NO_X control. Therefore, the States' final NO_X budgets promulgated in today's action do not assume implementation of additional highway or nonroad mobile source controls or expansion of existing controls beyond those described in the NPR. Further discussion concerning mobile sources, including the national measures EPA has assumed for purposes of today's rule, can be found in Section III, Determination of Budgets.

d. Other stationary sources. The EPA does not assume, in this rulemaking, any additional control measures or

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lower emissions levels for municipal waste combustors because these combustors are already being controlled through MACT regulations. Moreover, no additional control measures were assumed for source categories with relatively small NO_X emissions (e.g., iron and steel mills, nitric acid manufacturing sources, space heaters, lime kilns, recovery plants, and engine test facilities). Further discussion concerning why controls were not assumed for these source categories may be found in Section III of this preamble.

e. Conclusion. The above discussion described the controls for various source categories that EPA considers to be highly cost-effective. The next step in the process is to determine the amounts of NO_X emissions that would be eliminated by applying these highly cost-effective controls to the respective source categories. The EPA considers those emissions to be the amounts that contribute significantly to nonattainment in, or interfere with maintenance by, downwind States. By assuming that reductions of this magnitude should occur, EPA determined the resulting State-specific ''budget.'' Section III, Determination of Budgets describes the process EPA used to determine each State's budget and discusses comments received on the NPR.

E. Other Considerations

As described above, EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind State primarily by (i) evaluating, with respect to each upwind State, several air quality related factors, including determining that all emissions from the State have a sufficiently great impact downwind (in the context of the collective contribution nature of the ozone problem); and (ii) determining the amount of that State's emissions that can be eliminated through the application of cost-effective controls. Before reaching a conclusion, EPA evaluated several secondary, and more general, considerations. These include:

• The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems

• The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas

• General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls This section discusses these additional considerations.

1. Consistency of Regional Reductions With Attainment Needs of Downwind Areas

a. General Discussion. Currently, air quality levels in the eastern part of the United States are above the 1-hour NAAQS in various, primarily urban, areas. Air quality levels are also above the 8-hour NAAQS in those same areas, as well as many others.

The OTAG, and subsequently EPA, have conducted region-wide air quality modeling, using the UAM-V model, which shows that in approximately 20 primarily urban areas, the 1-hour nonattainment problem will persist by the year 2007, even after all of the controls specifically required under the CAA as well as Federal measures are implemented.[56] This nonattainment problem that remains after implementation of those mandated controls may be termed ''residual nonattainment.'' For the 8-hour NAAQS modeling shows that under the same circumstances, at least one urban area that is linked to each upwind State will continue to experience residual nonattainment, and significantly more areas will be in nonattainment as well.

Further, as discussed above, OTAG's subregional modeling as well as EPA's CAMx modeling and State-by-State zero-out UAM–V modeling, indicate that upwind States contribute significantly to those downwind nonattainment problems under both standards. In general, under the 1-hour standard, emissions from each upwind State affect at least several, primarily urban, nonattainment areas downwind. For example, each of the midwest/southern States of Ohio, Kentucky, Tennessee, West Virginia, Virginia, and North Carolina affects between five and eight downwind nonattainment areas. Under the 8-hour standard, emissions from each upwind State affect nonattainment problems that comprise an even larger geographic area. For example, Ohio, Kentucky, Tennessee, West Virginia, Virginia, and North Carolina each affect between eight to thirteen downwind States with nonattainment problems.

As described in section IV below, EPA has conducted additional regionwide modeling which shows that upwind reductions comparable to those required under today's rule have an appreciable impact on downwind nonattainment problems under both NAAQS. The downwind impact from each individual upwind State's reductions may be relatively small, but the impact from all upwind reductions, collectively, is appreciable. This regionwide modeling— which employs the UAM–V model relied upon by OTAG and also used by EPA for today's action— indicates that even after implementation of the regional reductions, which help downwind areas make progress toward attainment, certain downwind areas under the 1-hour NAAQS, and numerous downwind areas under the 8- hour NAAQS, will experience residual nonattainment. In addition, under the 8- hour NAAQS, many other areas with nonattainment problems are expected to reach attainment based solely on the regional reductions.

Furthermore, as mentioned earlier, the above-described modeling indicates no upwind States whose required regional reductions, in combination with the other regional reductions and CAA required controls, provide more ozone reduction than is necessary for every downwind nonattainment problem affected by that upwind State to attain under each NAAQS. That is, there is no instance of ''overkill,'' so that none of the upwind reductions required under today's action is more than necessary to ameliorate downwind nonattainment.

b. 8-Hour Nonattainment Problems. As indicated above, the upwind reductions are useful in ameliorating downwind nonattainment under both NAAQS, but they are particularly useful in areas with nonattainment problems under the 8-hour NAAQS because more areas have such problems under that standard. Emissions reductions from each upwind State affect a broader swath of downwind 8-hour nonattainment problems, including problems adjacent to, and further away from, the upwind State. For example, emissions from Ohio affect nonattainment problems in each State adjacent to Ohio, as well as numerous States further away. As noted above, in some cases, the upwind reductions eliminate the downwind nonattainment problem; in other cases, those reductions ameliorate the downwind problem but residual nonattainment remains.

Moreover, under the 8-hour NAAQS, upwind contributions tend to be a particularly large percentage of the downwind nonattainment problem. For example, along the Northeast corridor, cumulatively upwind States including adjacent States, contribute 83 percent of

[56] As described elsewhere, the controls specifically required under the CAA include the controls identified in the modeling baseline, as well as certain Federal controls such as NLEV. These controls do not include any additional reductions that may be required in the local nonattainment areas as part of their attainment demonstrations.

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Washington, DC's nonattainment problem; 68 percent of Maryland's nonattainment problem; 65 percent of Pennsylvania's nonattainment problem; and 85–88 percent of each of New Jersey's, New York's, Connecticut's, and Massachusett's nonattainment problems. These high levels of upwind contributions to widespread nonattainment problems—both near to, and far from, the upwind State—indicate that the regional reductions from the upwind areas may be expected to be useful in ameliorating downwind nonattainment under the 8-hour NAAQS.

c. Commenters' Concerns. Commenters argued that in the NPR that EPA failed to demonstrate that the proposed reductions in upwind emissions were necessary for downwind areas to demonstrate attainment. Commenters pointed out the lack of local attainment demonstrations under the 1-hour NAAQS.[57]

The EPA does not believe a local attainment demonstration is required before EPA can call on upwind States to reduce emissions pursuant to section 110(a)(2)(D). The EPA believes that available modeling analyses demonstrate that upwind reductions are necessary to help downwind areas come into attainment. The OTAG and EPA subregional modeling, UAM–V State-by-State zero-out modeling, and the CAMx modeling, described above, link each upwind State's emissions and downwind attainment needs, in a manner that is sufficient to support today's action. To reiterate, under the 1-hour NAAQS, the emissions reductions from each upwind State, combined with other emissions reductions, are needed to reduce downwind nonattainment problems. That need is underlined by the fact that the modeling relied on for today's action indicates residual nonattainment after implementation of all required controls and Federal measures. Even after implementation of the regional reductions, there is residual nonattainment for at least one downwind area linked to each upwind State. The same is true for the 8-hour NAAQS, as noted above.

The EPA recognizes that in the future, additional information may become available that would shed further light on the amount of emissions reductions needed for downwind areas to attain the NAAQS. Local-scale modeling may indicate more precisely the ambient impact of regional and local reductions on downwind nonattainment areas and the amount of any residual nonattainment. Nevertheless, it should be emphasized that the models relied on for today's action are state-of-the-art, and that their various inputs—particularly the inventories—have recently undergone close scrutiny and careful refinement through public comment and expert analysis. Accordingly, EPA believes that the overall model results indicating the general impact of upwind emissions and reductions in emissions should be viewed as valid. Accordingly, EPA believes that it has an adequate base of information to require the regional reductions under the 1-hour and 8-hour NAAQS at this time.

2. Equity Considerations

The EPA believes further justification for today's action is provided by overall considerations of fairness related to the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by those areas.

The OTAG and EPA modeling analyses clearly indicate that upwind emissions contribute more than trivial amounts to downwind nonattainment problems. As a result, upwind emitters are exacerbating the health and welfare risks faced by those who live and work in downwind areas afflicted with unhealthful levels of ozone. The EPA believes that the principle of simple fairness applies here: upwind States should reduce their emissions that visit those health and welfare problems upon their downwind neighbors. Otherwise, their downwind neighbors would be obliged to pay additional costs to reduce local emissions beyond what would otherwise be necessary to protect their health from upwind emissions. In EPA's judgment, it is fair to require the upwind sources to reduce at least the portion of their emissions for which highly cost-effective controls are available. Indeed, fairness considerations would point towards requiring upwind reductions even if there were some degree of cost inefficiency.

Further, it should be recognized that the major urban nonattainment areas have been required to incur control costs for ozone precursors since shortly after the 1970 CAA Amendments. In general, over the past quarter of a century, these areas have implemented SIP controls that, in combination with Federal measures, place ozone-related controls on virtually all portions of their inventory of ozone precursors, including VOCs as well as NO_x. The Air Quality Modeling TSD includes descriptions of the control measures in place for several major urban nonattainment areas. Although not every major urban nonattainment area has complied with every CAA requirement for ozone precursors, the major urban nonattainment areas have complied with almost all of these requirements, and the CAA provides remedies to assure complete implementation of the required provisions. These measures have already lead to substantial reductions in ozone levels. By comparison, upwind States have not implemented reductions intended to reduce their impact on downwind nonattainment areas.

3. General Cost Considerations

The EPA also generally considered the cost-effectiveness of additional local reductions in the 1-hour ozone nonattainment areas. The EPA conducted this analysis as part of its Regulatory Impact Analysis, completed under Executive Order 12866, for the rulemaking in which EPA revised the ozone NAAQS, 62 FR 38866 (July 18, 1997). The EPA surveyed the additional VOC and NO_x controls available in areas throughout the country that are expected to be nonattainment under either NAAQS. The EPA ascertained that nationally, on average, these additional measures would cost approximately $4,300 per ton removed during the ozone season. See ''Control Measures Analysis of Ozone and PM Alternatives: Methodology and Results,'' July 17, 1997, table VII–2, p. 56. Although this figure is a national average, it provides a basis to conclude that local reductions may be expected to be more expensive than the approximately $1,500 in cost per ozone-season ton removed for the regional NO_x reductions required in today's rulemaking.

Commenters criticized EPA's proposal to measure cost-effectiveness in terms of cost per ton of emissions removed because it did not take into account the ambient impact downwind of the emissions reductions. Commenters cautioned that under certain circumstances, a high level of emissions reductions upwind may result in high costs (even though cost-effective on a per-ton basis), but relatively little ambient benefit downwind. Commenters emphasized that emissions reductions tend to have the greatest ambient benefit when they are within, or adjacent to, the area with the nonattainment problem. Commenters also said that emissions reductions further upwind have less ambient benefit. Accordingly, commenters stated that EPA's cost-effectiveness

[57] As noted in Section II.A., EPA proposed two analytical approaches, the second of which is the same as EPA is today promulgating. The commenters's criticisms seem to apply equally to both approaches.

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justification did not support its proposed reduction requirements.

The EPA acknowledges the concerns expressed by the commenters that focusing solely on the cost effectiveness, defined in terms of cost per ton removed, of the emissions reductions would exclude consideration of the total costs incurred by the upwind sources, and would exclude consideration of the downwind ambient benefits that those costs achieve, compared to the costs of achieving the same ambient impact through either local reductions or more extensive reductions in adjacent upwind areas. The EPA further acknowledges air quality modeling makes clear that reductions in emissions closer to the air quality problem have a greater ambient impact.

However, EPA has not been presented with, nor been able to develop, an accurate comparison of the downwind costs of emissions reductions that would achieve the same ambient impact as the regional reductions required by today's action. The EPA does not have comprehensive information concerning available local measures or their costs or ambient impacts.

However, as a qualitative matter, EPA believes that available evidence indicates that the upwind costs are reasonable not only in light of cost-effectiveness per ton removed, but also in light of the downwind ambient impact of the emissions reductions. Under the 1-hour NAAQS, emissions from each upwind State generally affect several downwind nonattainment urban areas. Thus, matching the total ambient impact of the emissions reductions from the upwind State would require emissions reductions in several downwind areas.[58]

Although presently available information does not permit a useful quantitative comparison of total upwind and downwind costs in terms of their ambient impact, EPA believes that upwind reductions replace local reductions that, on a cost-per-ton removed basis, may be expected to be more expensive. Moreover, it should be recognized that for all of the nonattainment areas under the 1-hour NAAQS, the residents have already incurred substantial control costs to eliminate part of the local contribution to the air quality problem. Under these circumstances, EPA considers it equitable to require the upwind emitters to offset their contribution to the problem through at least the reductions that are the most highly cost-effective— in terms of cost-per-ton removed— rather than require the residents of the downwind area to offset those upwind contributions through even more local control measures.

Furthermore, under the 8-hour NAAQS, the available information— again, on a qualitative basis—indicates that the upwind emissions reductions replace a significantly greater set of local measures. As indicated above, emissions from each upwind State affect a wide swath of downwind areas with nonattainment problems. As a result, the emissions reductions from the upwind State replace local reductions in numerous downwind areas. Moreover, some of these downwind areas are adjacent to the upwind State, while others are further away. Thus, under the 8-hour NAAQS, EPA believes that the qualitative case is even more vivid that the upwind emissions reductions replace substantial and costly local measures.

Finally, with respect to the meteorological phenomenon that upwind reductions have less ambient impact the further away they are from the downwind nonattainment problem: EPA modeled the ambient impact of regional variations in the levels of upwind emissions reductions. This modeling, and its results, are discussed in the Air Quality TSD. In brief, the modeling results indicate that it is neither more cost-effective nor more beneficial to air quality to pursue subregional variations in upwind emissions controls.

4. Conclusion

For the reasons discussed above, EPA believes that adequate information is available to determine, on a qualitative basis, that the upwind reductions required by today's action are reasonable in light of the attainment needs downwind, and that the costs of those reductions are reasonable in light of the costs the downwind areas would otherwise face. For these and other reasons noted elsewhere, EPA believes that requiring the regional reductions in today's notice is a reasonable step to take at this time.

Of course, as more comprehensive information becomes available (including additional modeling, additional information concerning local control options and costs, as well as more refined regional air quality information), EPA will continue to examine the issue of regional transport. In addition, as described in Section III., EPA expects to review the issue of regional transport by the year 2007 and may require additional steps by either the upwind States or the downwind States, or both, to address the issue further. Even so, as noted above, the information that is available provides no evidence that the regional reductions required today may prove not to be needed.

III. Determination of Budgets

The EPA used the highly cost-effective measures identified in Section II.D. above to calculate the amounts of emissions in each covered State that will contribute significantly to nonattainment or interfere with maintenance in one or more downwind States (the ''significant amounts''). This Section further describes issues related to cost-effective controls and the role of these controls in the calculation of budgets.

First, as described earlier in this notice, EPA projected the total amount of NO_X emissions that sources in each covered State would emit, in light of expected growth, in 2007 taking into account measures required under the CAA (the ''2007 base year emissions inventory''). The EPA then projected the total amount of NO_X emissions that each of those States would emit in 2007 if each such State applied these highly cost-effective measures (2007 controlled inventory). The difference between the 2007 base inventory and the 2007 controlled inventory for each covered State is the ''significant amount'' that the State's SIP must prohibit to satisfy section 110(a)(2)(D)(i)(I). Each covered State's 2007 controlled inventory— referred to in this Section as the State's ''emissions budget''—expresses the total amount of NO_X emissions remaining after the State's SIP prohibits the ''significant amount'' of NO_X emissions in that State. Each covered State must demonstrate that its SIP includes sufficient measures (of the State's choice) to eliminate those emissions, and thereby meet its budget, in the time frames discussed later in this notice.

A. General Comments on the Base Emission Inventory

Background: In the NPR, EPA solicited comment on technical information used in revising the 1996 base year emissions inventories and the growth and control assumptions used to develop the 2007 projection year base inventories. The EPA received over 200 comment letters (from industry, associations, States, environmental organizations, and U.S. Congressional representatives) on the condition of 1996 base year and projected 2007 emission inventories. The EPA accepted

[58] Although the reductions required of any one individual upwind State under today's rule may not, by themselves, result in large ambient impacts downwind, those reductions, when combined with reductions from other upwind States, do result in appreciable reductions downwind.

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proposed modifications to the extent EPA was able to validate them.

As discussed in the NPR (62 FR 60318), EPA established a 120-day comment period (ending March 9, 1998) to address issues related to the proposed rule. In order to develop revised inventories used to recalculate the budgets for final rulemaking in a timely manner, EPA felt that comments received after the March 9, 1998 deadline would be addressed only if time and resources were available and after directing attention to comments received prior to the end of the comment period. The EPA is legally obligated under the Administrative Procedure Act to respond only to comments timely submitted during the public comment period. Response to comments timely submitted before the end of the comment period fulfills EPA's obligation to 5 U.S.C. 553(c).

Although the Agency was not able to address all comments submitted after March 9, 1998, as discussed in Section III.F.5. of this notice, EPA is allowing commenters an additional opportunity to request revisions to the source-specific data used to establish each State's budget. During this time, EPA will be addressing those comments submitted during the NPR and SNPR comment periods which were not addressed for reasons indicated above, as well as evaluate comments that are submitted per Section III.F.5. of the NFR.

1. Quality

Comment: Commenters suggested that the OTAG inventory may not be of sufficient quality for use in the modeling and budget determinations for the non-EGU point, area, nonroad mobile, and highway vehicle source sectors. The commenters stated that OTAG originally intended the inventories to be used in analyzing ozone transport mechanisms and the effect of possible control measures, not for establishing emission budgets as EPA has proposed. Additionally, as one commenter mentioned, many States had prepared inventories only for their moderate and above nonattainment areas, so that the remainder of the State's counties were supplemented with USEPA data. In contrast to these criticisms, other commenters supported the quality of the inventories and the procedures used in their development.

Response: Under the initial OTAG inventory collection process, the 37 States in the domain provided emission estimates for each entire State. The majority of the supplied data were 1990 State ozone SIP emission inventories, but some States supplied data from later years that reflected significant improvement over the 1990 data. Additionally, OTAG collected point source data from the States to update and revise existing emissions inventories used by OTAG. The result of these efforts was an improved emissions inventory which OTAG utilized for modeling as well as strategy analyses.

The EPA used the final OTAG version of the inventory for the emission estimates in the NPR, and then improved the inventory with data supplied by the States and industry through the public comment period. As a result, the revised emissions inventory is the most accurate available for modeling, strategy analyses, and budget calculation purposes. The inventory has been through numerous versions, each version reviewed and extensively commented on by States, industry, and the public. These inventory data are more accurate than any other data used in the past as the basis for the various State-specific SIP revisions (such as rate-of progress SIP revisions or attainment demonstrations). The EPA considers it sufficiently accurate for purposes of determining the budgets.

The EPA recognizes that emission inventories change as more accurate data or methods are developed for estimating emissions. For inventory changes that may be necessary after final promulgation of the budgets, EPA has a process for determining what changes need to be made as well as how the changes would be made to the inventories. This is discussed in further detail in Section III.F.5. of this notice.

Comment: Several commenters were concerned that the initial State NO_x emissions inventories submitted by the States were never quality-assured or commented upon by the States, the regulated community, or the public. Some commenters suggested the reevaluation of emissions estimates with State, local, and industry support.

Response: Under the guidance of OTAG, the initial emission inventories submitted by the States were quality-assured by technical experts, including State and local emission inventory contacts, industry, EPA staff and contractors, and the OTAG Emission Inventory Technical Committee. As EPA amended and modified the inventory for use in the modeling for the NPR, SNPR, and the budget analyses, additional quality assurance was completed. The most accurate inventory development tools available at the time were used to validate these data and to quality assure emission calculations in these data bases. Existing data sets, including the NET data, the OTC NO_X Baseline emission inventory, EPA'S AIRS/AFS major point source reporting system, and EPA's Emission Tracking System (ETS), which contains data submitted and certified as correct by the States, were used for comparison purposes. Where discrepancies were found, either before, during, or after the public comment period, States and industry were contacted to clarify and support revised emission estimates.

2. Availability

Comment: Commenters asserted that the emissions inventory used for the SIP modeling and budget calculations were not made available for public review along with the proposed rule. One commenter stated that the emissions inventory that forms the basis for the NPR (the SIP Call inventory) did not become available until the first week in February 1998.

Response: On October 10, 1997, EPA posted emissions data on the TTN for use and review during the public comment period (*See* NPR, 60318). These data, in conjunction with the OTAG inventories, were the basis of the initial proposed budgets and modeling analyses in the NPR. Thus, these data were available to the public before the beginning of the 120-day comment period on the NPR, which allowed ample time to develop budget, modeling, and cost analyses for submission during the comment period. By notice dated January 28, 1998 (63 FR 4206), EPA issued a caution that comments on the inventory must be submitted by the March 9, 1998 close- of-public-comment date, so that EPA could finalize the inventories and use them for further analyses.

On February 3, 1998, in response to initial public comments and internal review of the initially released data, draft amendments to the emissions inventory were posted on the EPA's TTN site. These changes included the addition of EGU sources less than or equal to 25 MWe which were excluded from the initial budget calculation, correction of EGU growth factors, and the reclassification to the non-EGU file of some sources previously erroneously identified by OTAG as EGU sources. Erroneously omitted non-EGU point source records were also added to the emissions inventory. Area, highway, and nonroad mobile source information was not modified in this iteration. By posting this data on February 3, 1998, EPA allowed 5 more weeks for public comment on the revised data, until the conclusion of the comment period for inventory data on March 9, 1998.

Because the revisions were fairly minor, EPA believes this amount of time was adequate. The EPA did receive comments by March 9, 1998 on the revised data it had posted on February 3, 1998.

B. Electricity Generating Units (EGUs)

Background: To determine the budget for each State's electricity generating sector, EPA developed an inventory of baseline heat input (mmBtu) and NO_X emissions (tons/season) data for each unit. In the NPR, EPA proposed to use the higher, by State, of 1995 or 1996 heat input data to calculate baseline heat input rates (62 FR 60352). The EPA maintained this approach for the SNPR, but added 577 smaller units to the State budget inventories, which had erroneously been omitted for the NPR. These units included electricity generating sources of 25 megawatts of electrical output (MWe) or smaller and additional units not affected under the Acid Rain Program.

1. Base Inventory

Comment: Commenters suggested that using the higher of 1995 or 1996 utilization rates for setting the baseline for the EGU portion of the budget may not be appropriate in all instances. In general, commenters argued for various degrees of flexibility in choosing the baseline year(s) to be used for calculation of budgets.

Response: As discussed below, EPA has made corrections to the baseline heat input data for a small number of EGUs based on careful review of the data supplied with source-specific comments. Using 1997 CEMS data is not a practical option because EPA has not had time to extract from the Acid Rain Emissions Tracking System (ETS) the 5-month ozone season heat input values, quality assure them, or publish them. (Although EPA's Acid Rain Program intends to publish its 1997 Emissions Scorecard later in 1998, this publication will contain only annual, not ozone season, data.) Accordingly, EPA has finalized the EGU portion of the budget for each State using the higher of the 1995 or 1996 ozone season heat input values.

Comment: Commenters asserted revisions were needed to the published heat input data for some EGUs and proposed related additional source-specific changes. Commenters on this issue stated that inaccurate calculations of heat input data resulted in significant errors in the Statewide budgets. Several suggested the need for revision before calculation of final budgets. Many of these commenters provided specific data that they urged EPA to use in the final budget setting process.

Response: The EPA has analyzed the data submitted by these commenters and, where warranted, has made the requested adjustments. Approximately 200 corrections were made to the baseline heat input data for EGU sector inventories.

Comment: Commenters also noted the need to further correct, for some States, the listing of units in the electricity generating sector inventory. Commenters listed specific EGUs that EPA should either include or remove from the inventory, or for which EPA should correct applicable baseline data (e.g., capacity, operating parameters). Several commenters argued that substantial revision of the inventory was necessary before setting budgets under the final rulemaking.

Response: The EPA has analyzed the data submitted by these commenters, including following up with commenters when needed to assure proper interpretation of the data. Where warranted, EPA has corrected the State inventories of units and applicable baseline data.

While the vast majority of corrections consisted of adding small units (e.g., municipal generators and peaking diesel units), combustion turbines, and independent power producers not affected under the Acid Rain Program, some involved deleting units that are no longer operational or have been misclassified and, in actuality, are industrial non-electricity generating boilers. The net result is that EPA has added approximately 800 units to the State EGU inventories. The EPA believes that these inventories are sufficiently accurate to develop a budget.

Comment: Commenters suggested types and sizes of sources to include or exclude from the electricity generating sector inventory. As to the sizes of sources to include in the inventory, commenters on the NPR were roughly split on the inclusion of units less than or equal to 25 MWe. Several noted that emissions from sources below this level were negligible and should not be included. One commenter noted, however, that these sources should be included in the final budget because they tend to operate on peak demand days which frequently correspond to high ozone days. Several suggested that 15 MWe be the cutoff for the utility component of the budget.

On a separate concern, a few commenters disagreed with the inclusion of non-utility power generators in the utility list of sources and proposed that they be included with industrial non-electricity generating unit sources.

Response: Many of these comments appear to confuse discussions of other related issues (e.g., core sources for NO_X cap and trade rule, appropriate sources for cost-effective control) with the types and sizes of EGUs to be included in the baseline inventory for setting the budget. All emissions should be included in the base inventory and, thus, in the budget. As noted previously, using information supplied by commenters, EPA has agreed to add many small units to the base inventories of several States. Concurrently, EPA has also decided not to classify EGUs less than or equal to 25MWe as core sources for the trading program, as discussed in Section VII of this notice, or to assume an emissions decrease for these small units (''cutoff level'') as part of Statewide budgets for EGUs.

The EPA maintains its decision to include industrial units that generate electricity in the definition of EGUs is entirely consistent with the changing, more competitive, character of today's electric power generation industry in the US. Also, these units are amenable to the same NO_X control technologies, at generally the same cost-effectiveness, as utility units.

2. Growth

Background: In the NPR and SNPR, EPA used forecasts of future electricity generation to apply State-specific growth factors in calculating the emissions budgets for the electricity generating sector. In the SNPR, EPA revised the growth factors (the ''corrected'' projections) to account for projected new combustion turbine and combined cycle units inadvertently excluded in the analysis developed in support of the NPR. The EPA also discussed in the SNPR that ''revised'' electricity generation projections could lead to lower growth rates, and therefore lower budgets, and placed supporting information in the docket. However, EPA proposed to use the ''corrected'' projections in calculating State budgets to provide additional compliance flexibility to sources and States (63 FR 25905).

a. Growth Rates.

Comment: The EPA received approximately 36 comments in response to the NPR and roughly 28 comments in response to the SNPR regarding the estimated growth rates that were used to determine the NO_X budget for each State. These comments were submitted by State agencies, associations, utilities, and a public interest group. Commenters expressed concern regarding a number of specific issues, including the following:

(i) the appropriateness of using growth factors to determine the NO_X budget,

(ii) use of the IPM model to establish the growth factors for each State, and
(iii) the use of the ''corrected'' instead of the ''revised'' projections.

Some of these commenters opposed growth factors generally, but many of them supported the concept of—but not the method proposed for—applying a growth factor.

Response: The OTAG's technical analyses of NO_X emissions suggested that EPA needed to consider the electric power industry's future growth in determining the amount of NO_X reduction that would be reasonable for the power industry to make in the future. The OTAG factored the growth of the power industry's emissions from 1990 to 2007 into the air quality analysis that it performed. The results of this analysis were the basis of its recommendations to EPA to lower NO_X emissions from the power industry in many Eastern States. Because the Agency made its predictions about attainment in 2007 based on projections of emissions considering growth, rather than on historical emissions, the Agency also believes that the State budgets to be used up to 2007 should account for growth in electricity demand. Not accounting for growth in demand for electricity would require States to reduce emissions below the level that EPA predicted was necessary to reach attainment. By accounting for growth through 2007 and applying that growth beginning in 2003, EPA essentially allows sources to emit at a slightly higher level than 0.15 lb/mmBtu in the years 2003 through 2006.

In today's action, the Agency has determined to continue to incorporate growth out to 2007 in developing State budgets for summer NO_X emissions. Not accounting for growth would mean that additional control measures—to offset growth—would be required, and EPA has not determined that those additional control measures would be cost-effective. In considering growth, EPA has determined to continue to use either 1995 or 1996 State-wide heat input data, for whichever year was higher for units over 25 megawatts that burn fossil fuels for baseline data. (More details on this approach can be found above in Section III.B.1. Base Inventory).

To estimate growth, EPA considered several options. Ultimately, the Agency has decided to use State-specific growth factors derived from application of the Integrated Planning Model (IPM) using the 1998 Base Case [59] (also referred to as the ''revised'' growth factors). This is the same Base Case used for the Regulatory Analysis in support of the SNPR. The reasons for using these data are discussed below under ''Use of IPM.''

b. Use of IPM.

Comment: Many commenters questioned whether use of the IPM model was appropriate to derive accurate State-specific growth factors. Commenters expressed concern that there was too much variation between each State's individual growth rate as determined by the IPM model, and suggested that use of region-wide IPM growth factors may be more appropriate. They also questioned the reliability and accuracy of the IPM model, especially as applied on an individual State basis. A number of commenters stated that EPA's growth projections were lower than growth rates projected in the context of State utility planning efforts. Several commenters suggested that EPA base its growth rates on projections other than OTAG, or EPA's IPM forecasts; they especially urged the Agency to consider individual State-prepared forecasts. This was to avoid problems that commenters believe exist in EPA's use of the IPM model for forecasting electricity generation in various areas of the country. Specific concerns focused on:

(i) the effect of IPM projections and associated NO_X budgets on future growth within each State, and
(ii) how the IPM model accounts for:
—planned nuclear unit retirements,
—the impact of a deregulated utility marketplace, and
—improvements in energy efficiency and control technology.

Many commenters also generally expressed concern that there is insufficient information or documentation on how EPA used the IPM model to determine growth factors.

Many commenters asserted that EPA should not incorporate the growth factors into the budget calculation process. These commenters argued that adding growth to baseline activity and subsequently applying controls reduces the stringency of the standards, and introduces an unacceptable level of uncertainty. They suggested that the budgets should be based on historic utilization rates, and that States could then determine how to allocate their budgets to provide for growth. These commenters recommended that, if a growth factor must be used, then EPA should apply a uniform growth rate region-wide to determine the NO_X budget for each State.

Response: The EPA initially considered using the OTAG growth rates, but found that they were largely based on past, State-specific generation trends and did not factor in the more competitive electric power market where electricity will be increasingly moving between regions in response to the cost of producing electricity. The Agency also found that there were several other major limitations that were described in the NPR. (62 FR 60352–60353).

The Agency considered setting the State NO_X budgets based on past generation levels in States, but this approach also does not consider how competition in the industry in the future will alter electricity generation practices. It ignores growth and shifts in production altogether. A variant of this approach, suggested by several commenters, would be to use a uniform growth factor for all States based on some projection of future growth through the 23 jurisdictions covered by this rule. This approach appears even- handed, but EPA views it as unfair and inaccurate with respect to States in which:

(i) utilities are particularly economical to operate, and
(ii) the generation of power by these firms is expected to grow at a rate greater than average.

Another similar alternative suggested in the public comments was that EPA use a uniform growth factor for all States in the same region, e.g., the North American Electricity Reliability Council (NERC) regions, or subregions. The problem with this approach is, again, that certain States within the same region are expected to vary in their rate of growth, given differences in their electric utilities. The fact that some States are in several NERC regions also makes this approach less practical.

The Agency looked at several well-recognized forecasts of regional electricity generation growth, such as those provided by NERC, the *Annual Energy Outlook* of the Energy Information Administration (EIA), and Data Resources Incorporated's (DRI) *World Energy Service U.S. Outlook*. None of these modeling systems provides results at the State level. Therefore, the Agency would have to develop ways to apportion these regional predictions to States. The EPA knows of no way to apportion these regional values to States that would resolve the concerns expressed by commenters. Furthermore, the Agency uses the growth rates from IPM to calculate the cost-effectiveness of NO_X emission reductions, as well as to determine NO_X budgets for States. Therefore, using growth rates that are not from IPM would lead the Agency to using one set of State-specific

[59] The Base Case is the condition of the industry in the absence of the SIP call.

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generation estimates to develop NO_X budgets and a different set of State-specific generation estimates for determining cost-effectiveness. As a result, EPA's evaluations of future activities of the power industry might not be considered consistent. Finally, although each of these sources provides reasonable electricity generation forecasts, each of the forecasts could be criticized for the assumptions they make in a manner similar to the way commenters have criticized growth factors from IPM.

Some commenters suggested that the Agency use individual State forecasts instead of IPM forecasts, including projections used for State utility planning efforts. The EPA rejected this type of approach for two reasons. First, nothing in the comments suggested to EPA that the State forecasts are more accurate or more reliable than the IPM forecasts. Instead, the State forecasts varied State by State in the way they predicted future electricity generation. Adoption of these forecasts could result in inconsistencies in setting the State budgets. Electricity generation forecasts require making many technical assumptions which, admittedly, lead to some uncertainty in the results. Accordingly, the Agency believes that the fairest way to determine emissions budgets is to handle these assumptions in a consistent way for all of the States, as long as a reasonable approach and reasonable modeling assumptions are used.

Therefore, EPA has decided to use the IPM 1998 Base Case emissions forecast for deciding State NO_X budgets in today's action. The Agency finds it to be the fairest and most reliable overall approach to estimating growth factors. It deals consistently with the technical assumptions that occur in energy forecasting and employs a reasonable set of assumptions in the process of making a forecast. As an added advantage, it has undergone considerable review by the electric power industry over the last two years, and the industry was aware that it might be applied as it is in today's rulemaking. Finally, EPA's use of IPM for forecasting State growth rates provides for overall consistency in forecasting future emissions and estimating the cost-effectiveness of reductions in this rulemaking.

The EPA believes that IPM provides a reasonable forecast of State growth rates because it carefully takes into account the most important determinants of electricity generation growth that are facing the power industry today. These major factors include: regional demands for electricity, the impacts of wholesale competition that lead to changes in market share for various utilities, changes in fossil fuel prices, expected improvements in electricity generation technology, costs of emission control technology, expected changes in generation unit operations and regional dispatch practices to lower production costs, nuclear unit retirements, alteration in planning reserve margins to meet peak demand, and limitations in moving power between regions due to transmission constraints.

An explanation of how EPA uses IPM to address these issues and other important factors is included in EPA's *Analyzing Electric Power Generation under the CAAA* , March 1998 (Docket no. V–C–3). Because EPA's assumptions have been reviewed by the public over the last two years and the Agency has worked with EIA and other groups to improve them in response to comments and new information, the Agency believes that it has made reasonable assumptions for a Base Case forecast of electric power generation.

c. Use of ''Corrected'' Growth Rates.

Comment: Some comments on the SNPR expressed concern that the new ''corrected'' growth factors are artificially inflated and will compromise efforts to improve air quality throughout the region. Some of the commenters suggested that States should have the flexibility to determine how to manage emissions from new sources in the context of the original growth factors and NO_X budgets proposed in the NPR. Some of these commenters also stated that it was unclear why EPA chose to use the ''revised'' projections in its cost analysis but retained the ''corrected'' growth factors in its budget calculations. Other commenters, however, were supportive of the new growth factors and the use of the ''corrected'' projections. Finally, several commenters requested that EPA further explain how the ''corrected'' growth factors were derived and subsequently used to generate the NO_X budgets.

Response: In the NPR, EPA proposed a set of growth factors based upon the 1996 IPM Base Case forecast. In the SNPR, EPA corrected the growth factors used in calculating State budgets to account for new generation that had inadvertently been left out of the original calculations (the ''corrected'' growth factors). On the basis of comments that EPA has received on its assumptions for forecasting electricity generation throughout the country during the last year, the Agency revised a set of key assumptions at the beginning of 1998. These assumptions lead to a better projection of electricity generation nationally, by region, and by State. Therefore, the Agency has decided to use the 1998 IPM Base Case forecast over the 1996 IPM Base Case forecast as the basis for its ''revised'' State growth estimates.

The recent important changes that were incorporated into EPA's use of IPM in 1998 include using the most recent NERC estimate of regional electricity demand; the latest available EIA and NERC generation unit data; updated fuel forecasts; updated assumptions on nuclear, hydroelectric, and import assumptions (with special attention to differences in summer use); and an increase in the level of detail in the model to more accurately capture the transmission constraints that exist for moving power between various regions of the country. The Agency also updated its assumptions on the size and operation of all electricity generation units of utilities and independent power producers (with special attention to cogenerators) and updated its assumptions on planning reserve margins and the costs of building new generation capacity. For this, the Agency relied heavily on information compiled from utilities by NERC and the EIA. Each of these agencies has regular contact with the power industry and has its data reviewed by the power industry. Again, details on these improvements in IPM can be found in EPA's *Analyzing Electric Power Generation under the CAAA* , March 1998 (Docket no. V–C–3).

In the SNPR, EPA used the ''revised'' growth factors in the IPM model in its cost analysis but used the higher, ''corrected'' growth factors to calculate State budgets. The EPA proposed the higher growth factors because the Agency believed that this results in less cost and more flexibility for sources to achieve their budget reductions beginning in 2003. However, some commenters pointed out that EPA had provided sufficient flexibility by accounting for growth to the year 2007 and applying that growth estimate beginning in 2003. These commenters remarked that it was not necessary to add further flexibility by using the higher, but less current and less accurate, ''corrected'' growth rates. They also stated that EPA should use the most up-to-date information available. The EPA agrees and is using the ''revised'' growth rates based upon the 1998 IPM Base Case forecast to calculate the State budgets used in today's final rule.

3. Budget Calculation

a. Input vs. Output.

Background: In the SNPR, the component of each State's budget assigned to electricity generation was determined using the State's total heat

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input, applicable emission rate (0.15 lb/ mmBtu), and projected growth in total heat input to 2007. The Agency solicited comment on an alternative approach to calculating the State's budget using each State's share of the 23 jurisdiction electricity generation (electrical output). The SNPR describes in detail the output-based approach, and its possible benefits as advanced by its proponents (63 FR 25907). The Agency asked for comments on the appropriateness, legality, rationale, and methodology for incorporating the output-based approach when calculating the electricity generation component of each State's budget.

Comments: The Agency received comments both supporting and opposing output-based State budgets. Supporters of output-based budgets asserted:

- An output-based budget would promote competition among different types of electricity providers on an equal basis in a deregulated electric utility industry.
- An output-based budget would promote CO_2, mercury, SO_2 and off-season NO_X reductions beyond what would occur under a system that assigns State budgets based upon input.
- An output-based budget may result in more cost-effective NO_X reductions.
- Issuing output-based budgets is legally permissible.

The commenters opposed to output-based State budgets objected to the allocation of allowances to non-NO_X-emitting units, such as nuclear, hydroelectric, solar, or geothermal power plants. They claimed that this would make compliance more difficult and more costly for fossil-fuel burning sources because fewer allowances would be allocated to them.

Commenters opposed to output-based budgets also claimed that:

- Output-based budgets would not necessarily improve energy efficiency compared to existing incentives, such as fuel costs.
- The output-based State budgets may not result in the same geographic distribution of emissions as would occur under the original budget allocation.
- There could be significant administrative problems with changing the basis of the State budgets.

In addition, some commenters, though in general supporting allocations by output, specifically objected to allocating allowances to nuclear-powered units because they believed that this method would encourage nuclear-powered electrical generation, which, they further believed, would have adverse ancillary impacts on the environment.

The Agency received additional comments on the method of allocating State budgets to sources. Further discussion of these comments can be found in Section VI.C.2 of this preamble.

Response: The EPA has an extensive history of promoting the efficient use of natural resources, particularly energy, through both voluntary and regulatory measures. Key emissions standards, such as the standards for new vehicles and the recently promulgated new source performance standards to new power plants, are written as output-based fuel-neutral performance standards that promote the efficient use of energy. The EPA has begun to work with States to find mechanisms to more directly credit the use of energy efficiency measures in SIP. The EPA also has a number of programs that encourage the use of energy efficient technologies by providing energy users, particularly in the residential, commercial and industrial sectors, with information on the economic and environmental benefits of such technologies.

Although the Agency has concluded, for the reasons stated below, that heat- input-based budgets to States are more appropriate at this time, the EPA intends to work with stakeholders to overcome existing obstacles and to design an output allocation system that could be used by States as part of their trading program rules in their SIPs and by EPA in future allocations to States.

The EPA considered how State NO_X budgets would be changed using the output approaches suggested by the commenters. The EPA revised its State budget calculations using available electrical generation data from the EIA for utility and non-utility generators for the higher electrical generation output of either 1995 or 1996, by State. In Table III–1 below, Column 2 presents the proposed budgets based upon heat input. Column 3 presents the revised budgets based upon heat input and the revised growth factors. Column 4 shows output-based budgets, based upon all electrical generation. Some commenters suggested including fossil-fuel and renewable energy source generation—including hydroelectric, solar, wind, and geothermal generation—but not nuclear generation. These are included in Column 5. One commenter suggested using electrical generation from fossil- fuel only, which is included in Column 6.

TABLE III–1.—STATE BUDGETS BY ENERGY SOURCE BASIS

(Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
State	Proposed input-based budgets fossil fuel-burning generators	Revised input-based budgets fossil fuel-burning generators	Output-based budgets all generation sources	Output-based budgets—all generation sources except nuclear	Output-based budgets fossil fuel-burning generators
Alabama	30644	29026	34832	35068	32744
Connecticut	5245	2583	7677	5156	4456
Delaware	4994	3523	2392	3214	3417
District of Columbia	152	207	100	133	142
Georgia	32433	30255	32223	31713	30819
Illinois	36570	32045	44253	27888	29602
Indiana	51818	49020	32212	43285	45831
Kentucky	38775	34923	24847	33389	34166
Maryland	12971	15033	13284	12969	13212
Massachusetts	14651	14780	11017	13248	13496
Michigan	29458	28165	32275	32037	32457
Missouri	26450	23923	19790	22700	23498
New Jersey	8191	10863	12764	11227	11470
New York	31222	30273	39503	39440	32114

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TABLE III–1.—STATE BUDGETS BY ENERGY SOURCE BASIS—Continued

(Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
State	Proposed input-based budgets fossil fuel-burning generators	Revised input-based budgets fossil fuel-burning generators	Output-based budgets all generation sources	Output-based budgets—all generation sources except nuclear	Output-based budgets fossil fuel-burning generators
North Carolina	32691	31394	32006	30156	29866
Ohio	51493	48468	39790	47143	50019
Pennsylvania	45971	52006	53450	47014	48476
Rhode Island	1609	1118	2242	3012	3202
South Carolina	19842	16290	23252	14085	13831
Tennessee	26225	25386	26410	26084	24770
Virginia	20990	18258	19091	15700	15567
West Virginia	24045	26439	22853	30708	32527
Wisconsin	17345	18029	15745	16637	16324
Total	563785	542007	542007	542007	542007

The Agency then calculated the effective NO_X emission rate for each State in terms of lb/mmBtu, assuming that the entire electricity generation component of the budgets, as determined by the input or output methods, were allocated to the electric generating units (EGUs). The Agency wanted to evaluate whether the effective NO_X emission rate would be too low to prove feasible absent participation by the State in an interstate NO_X emission trading program. The EPA found that under output-based State budgets from all generation sources, three States would need to impose an effective emission limitation of 0.10 lb/mmBtu or less on their fossil-fuel burning electricity generators (see Column 3 in Table III–2 below). One State would need to impose an emission limitation of 0.07 lb/mmBtu. Such a low effective emission limitation may not be technically achievable if a State chooses not to join an interstate allowance trading program, unless the State requires some sources to shutdown. In contrast, the Agency found that it was feasible and cost-effective to make reductions even without an interstate NO_X trading program under an input- based State budget calculated using a uniform NO_X emission rate of 0.15 lb/ mmBtu.

TABLE III–2.—EFFECTIVE EMISSIONS RATES FOR EACH STATE BY OUTPUT BASIS

[Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5
State	Effective emission rate under input-based budgets (Fossil fuel burning generators) (lb/mmBtu)	Effective emission rate under output-based budgets (All generation)	Effective emission rate under output-based budgets (all generation except nuclear)	Effective emission rate under output-based budgets (Fossil fuel-burning generators)
Alabama	0.15	0.18	0.18	0.17
Connecticut	0.15	0.45	0.30	0.26
Delaware	0.15	0.10	0.14	0.15
District of Columbia	0.15	0.07	0.10	0.10
Georgia	0.15	0.16	0.16	0.15
Illinois	0.15	0.21	0.13	0.14
Indiana	0.15	0.10	0.13	0.14
Kentucky	0.15	0.11	0.14	0.15
Maryland	0.15	0.13	0.13	0.13
Massachusetts	0.15	0.11	0.13	0.14
Michigan	0.15	0.17	0.17	0.17
Missouri	0.15	0.12	0.14	0.15
New Jersey	0.15	0.18	0.16	0.16
New York	0.15	0.20	0.20	0.16
North Carolina	0.15	0.15	0.14	0.14
Ohio	0.15	0.12	0.15	0.15
Pennsylvania	0.15	0.15	0.14	0.14
Rhode Island	0.15	0.30	0.40	0.43
South Carolina	0.15	0.21	0.13	0.13
Tennessee	0.15	0.16	0.15	0.15
Virginia	0.15	0.16	0.13	0.13
West Virginia	0.15	0.13	0.17	0.18
Wisconsin	0.15	0.13	0.14	0.14

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Advocates of an output-based approach contend that individual sources would have the greatest incentive to improve their efficiency, relative to all other sources in the program, if both State budgets and individual source allocations were on an output basis and were updated periodically. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_X emissions proportionately, while the associated generator would produce the same amount of electricity. Thus, the company would receive the same allowances if an output-based allocation were updated after the efficiency improvement. This same company would receive fewer allowances under a system that reallocates based on heat input after the efficiency improvement. The company would keep the same allowance allocation if it had a permanent allocation, based upon either heat input or output. With a permanent allocation, the company would have more allowances available than before its efficiency improvements because of its emission reductions, but fewer allowances than if it had greater electrical output recognized through an updated allocation. Thus, of the four approaches, an updated allocation based upon output gives the greatest incentive for improving efficiency in electricity generation.

To provide an incentive within the State budget determinations for improving efficiency over time, EPA would need to issue the State budgets based upon output and periodically update those State budgets. However, many industry commenters wanted long-term or permanent allowance allocations to allow for compliance planning. Updates to the State budgets would require States to reallocate allowances to their sources. In addition, States (both upwind and downwind) would find it easier to manage their resources for improving air quality if they receive a fixed budget for a period of years. With a fixed budget, a State would have the choice of whether to periodically adjust allocations rather than being required to periodically reallocate allowances to its sources.

Finally, the Agency continues to have concerns about data available to establish the baseline for an output-based State budget. The EIA withholds some of the electricity generation information it collects from non-utility generators in order to protect source confidentiality. Therefore, part of the generation data required to establish State budgets is not available to EPA. Thus, EPA would have difficulty in computing and defending State budgets.

In addition, some units are cogenerators, which are electrical generators that divert part of their heated steam to provide heat (steam output), rather than to generate electricity. Information on steam output from cogenerating units or from industrial boilers is not currently available to EPA. A cogeneration unit that was included under the State budget as an electricity generating unit based upon heat input would only have its electrical output included in an output-based State budget, ignoring the portion of heat input used to generate steam output. Thus, output-based State budgets based on currently available data could inadvertently underallocate budgets to States with many cogenerators, which are some of the most efficient units. This could actually discourage improvements in efficiency through cogeneration.

For the reasons stated above, the Agency concludes that it is not appropriate to develop output-based State NO_X emission budgets at this time. However, the Agency does believe that output-based allocations to sources could provide significant benefits. As stated earlier in this Section, the EPA intends to work with stakeholders to overcome existing obstacles and to design an output allocation system based on electricity and steam generation that could be used by States as part of their trading program rules in their SIPs. In addition, EPA is proposing FIPs for States that do not submit adequate SIPs by the deadline required by this final rulemaking. As part of its proposal, the Agency is soliciting comment on source allocations for each State based upon both input and output. While EPA believes that the output data are not sufficiently complete or accurate to use for final budgets or for final source allocations at this time, the Agency is taking comment on the proposed allocations in order to receive public comment and to develop more accurate and more complete output data that could be used in the final FIP rulemaking.

The EPA does believe that, over the long-term, it should continue to look at the issues that surround the use of output-based allocations. In addition, as stated in Section III.B.5. of this preamble, the Agency will review the progress of States in meeting their budgets in 2007. In that review, the Agency will consider not only whether the SIPs achieved the reductions that had been projected to meet the budgets, but also issues such as future budget levels and allocation mechanisms including shifting to an output-based allocation method.

b. Alternative Emission Limits.

Comments: The EPA received numerous comments on the proposed uniform control level of 0.15 lbs/mmBtu for the EGU sector assumptions across the 23 jurisdictions. Many States supported this proposed control assumption. The EPA also received a number of alternative proposals. These contain emission-reduction assumptions ranging from 0.12 lb/mmBtu to be implemented on the schedule proposed in the NPR to a phased approach that starts with 0.35 lb/mmBtu to be implemented by sector and provides for further evaluation of the need for more stringent levels. The latter commenters based their recommendations on their views that emissions from upwind States do not have an ambient impact that is as important as EPA believes, or that implementation of the EGU control levels proposed by EPA would not be feasible by the date EPA proposed. In addition, a number of utilities and other commenters voiced concern that the proposed control assumption of 0.15 lb/mmBtu would be too stringent to provide sufficient surplus allowances for trading.

Response: At the time of the proposal, EPA chose 0.15 lb/mmBtu as the assumed uniform control level for EGUs because it provided the greatest air quality improvements feasible and was cost-effective because its cost ($1,700 per ton NO_X removed in the 5-month ozone season) was, on average, within the cost range of other controls that had been recently promulgated or proposed. The EPA also investigated the costs of several alternative uniform control options: 0.25, 0.20, and 0.12 (though 0.12 resulted in lower emission levels, its average cost-effectiveness calculated at the time of the proposal was $2,100/ton, exceeding EPA's target cost range of $1,000 to $2,000/ton).

Subsequent to the NPR and SNPR, EPA updated its EGU costing model (IPM) and revised stationary source emission inventories (based on public comment). These revisions and corrections lowered the average cost of compliance for all the control levels considered. Additionally, EPA conducted extensive air quality modeling of a number of alternative control levels. The results of the air quality analyses were examined using a number of different metrics for both the one-hour and eight-hour standards. These air quality analyses are discussed in more detail in Section IV of this notice.

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The revised air quality analyses show that there is no ''bright line'' to illustrate at what control levels the air quality benefits begin to diminish. The air quality metrics suggest there are corresponding incremental air quality improvements at every incremental control level. For example, tightening the control level improves ozone levels in many non-attainment areas and leads to additional counties achieving attainment under the one-and eight- hour standards. All metrics analyzed show that as the control level moves from 0.25 to 0.20 to 0.15 to 0.12 lb/ mmBtu, air quality benefits increase.

The analyses also show that none of the alternative control options results in attainment of the ozone standard in all nonattainment areas.

The EPA did not select levels higher than 0.15 lb/mmBtu (such as 0.20 lb/ mmBtu or higher) because the 0.15 lb/ mmBtu level offers more air quality benefits at a cost that is still highly cost-effective. Moreover, EPA did not have information to indicate that these higher levels could be implemented meaningfully sooner than controls at the 0.15 lbs/MmBtu level. The EPA acknowledges that the 0.12 lbs/MmBtu emission level is also within the average cost-effectiveness range based on the revised cost analysis. The incremental cost-effectiveness of this option is $4,200 per ton, an incremental cost per ton which is 85 percent higher than that for the 0.15 lb/mmBtu level. However, for reasons explained Section II.D., the EPA is not relying on this emission level.

The revised IPM analyses project that under the 0.12 control option, 54 percent of affected EGU capacity should install selective catalytic reduction (SCR) and 41 percent should install selective non-catalytic reduction (SNCR). The installation requirements for SNCR are significantly less extensive than for SCR. The analysis of the 0.15 lb/mmBtu control option projects 31 percent of affected EGU capacity should install SCR and 54 percent should install SNCR. Further, the technical record provides many examples in the United States and internationally of the ability of coal-fired units to achieve emission levels below 0.15 lb/mmBtu with the installation of SCR. The record contains fewer international examples, and only one US example, of a coal-fired unit's ability to achieve emission levels below 0.12 lb/mmBtu.

In terms of the proposed level of control on which the trading program budget is based, EPA believes that trading at 0.15 lb/mmBtu is feasible because the proposed limit can readily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_X levels below 0.15 lb/mmBtu and should readily be able to generate emission credits if affected States join a trading program.

The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/ mmBtu emission limit, SCR would generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/ mmBtu by installing SCR, it can provide emission credits to another coal-fired boiler and obviate the need for that second boiler to install SCR.

A remaining issue is whether SCR can achieve NO_X levels below 0.15 lb/ mmBtu. The EPA believes that SCR technology is capable both of reducing NO_X emissions by more than 90 percent and reducing NO_X rates below the proposed 0.15 lb/mmBtu limit, provided the appropriate regulatory incentive (i.e., emission limit or economic incentive) exists. As discussed in EPA's recent report, ''Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units,'' emission rates below 0.15 lb/mmBtu are currently being achieved by a number of coal-fired boilers using SCRs. Examples include: (1) Three Swedish boilers achieving rates between 0.04 and 0.10 lb/mmBtu; (2) six German boilers achieving rates between 0.08 and 0.14 lb/mmBtu; (3) two Austrian boilers achieving rates between 0.08 and 0.12 lb/mmBtu; and (4) four U.S. boilers achieving rates between 0.07 and 0.14 lb/mmBtu. The EPA also recognizes that these boilers, with the exception of the Swedish boilers, have SCR systems designed to achieve target emission limits. As a result, they fail to provide an accurate picture of the emission levels which SCR is capable of achieving below the target emission threshold. For this reason, EPA cannot confidently conclude that enough units can feasibly achieve levels at 0.12 lbs/ MmBtu. In summary, EPA believes that an emission rate of 0.15 lb/mmBtu reflects the greatest emissions reduction that EPA can confidently conclude is feasible and that is highly cost-effective, and provides ample allowances to sustain a market under the NO_X Budget Trading Program.

c. Consideration of the Climate Change Action Plan.

Background: The President's Climate Change Action Plan (CCAP) calls for implementation of over 100 voluntary programs aimed at reducing greenhouse gas emissions. A large number of them are aimed at reducing future electricity demand throughout the country.

Already, some of these programs have shown striking results in accomplishing their energy efficiency objectives.

Comment: Two commenters noted that it is inappropriate for EPA to incorporate assumed reductions in energy use based on the voluntary measures of the CCAP, which are not binding like a regulation.

Response: The EPA believes that it is appropriate to incorporate the impact of the voluntary measures in the CCAP on future electricity demand. The EPA has always believed that it is appropriate to incorporate any reasonable assumptions that the Agency can support that will affect future electricity demand, or electricity generation practices, into its Base Case forecast. For example, improvements in electricity generation technology, fuel prices changes, and other types of assumptions that are important elements of EPA's forecast of electricity generation and resulting air emissions are also not mandated by regulation. The Agency has considered the impact of the CCAP in using the IPM model for analysis since 1996, and documentation of the assumptions that the Agency has been making have been available for public review since April 1996. Until now, there have been no challenges to this consideration in the numerous reviews that there have been of EPA's documentation of how it uses the IPM model. Also, no one has challenged EPA's specific approach to factoring the CCAP into its electricity generation forecast. (This can be confirmed by examination of the dockets for the Clean Air Power Initiative and the Phase II Title IV NO_X Rule, records of EPA's Science Advisory Board, and the records of the Ozone Transport Assessment Group meetings.) The EPA updated its assumptions in IPM for the CCAP at the beginning of 1998. The EPA updated its assumptions in the same manner as it has done in the past—by lowering the most recent NERC demand forecast by the amount of electricity demand between 2000 and 2010 that the best available analysis suggests will occur due to the activities in CCAP. The EPA used the in-depth evaluation of the future implications of the CCAP for reducing electricity demand that was the basis for the findings in the Administration's Climate Action Report, July 1997. The amount of demand reduction that occurs appears in Analyzing Electric Power Generation under the Clean Air Act, March 1998. The Climate Action Report analysis was reviewed extensively within the Federal government by EPA, the Department of Energy and other Federal agencies, and the report was reviewed publicly before its publication. The EPA has not received criticism that it has overstated

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the electricity demand reductions that are the basis for the carbon reductions under the CCAP.

Notably, the electricity demand reductions were distributed evenly throughout the United States, and therefore have no influence on the share of the total amount of NO_X emissions that each State receives. Furthermore, the Agency examined the implications on its cost-effectiveness determination of not including the CCAP reductions in its electricity demand forecast. The EPA found that even if the Agency did not assume the CCAP reductions, it was still highly cost-effective to develop a regional level NO_X budget for the electric power industry, based on the level of control that EPA has assumed. (These results appear in Chapter 6 of the Regulatory Impact Analysis for the Regional NO_X SIP Call, September 1998.)

C. Non-EGU Point Sources

Background: The EPA developed the NO^X SIP call emissions inventory for non-EGU point sources based on data sets originating with the OTAG 1990 base year inventory. The OTAG prepared these base year inventories with 1990 State ozone SIP emission inventories, and EPA supplemented them with either State inventory data, if available, or EPA's National Emission Trends (NET) data if State data were not available.

For the SNPR, non-EGU point source inventory data for 1990 were then grown to 1995 using Bureau of Economic Analysis (BEA) historical growth estimates of industrial earnings at the State 2-digit Standard Industrial Classification (SIC) level. These emissions were grown to 1995 for the purposes of modeling and to maintain a consistent base year inventory with the EGU data. Because BEA data are historical documentation of industry earnings, EPA considered these to be among the best available indicators of growth between 1990 and 1995 (63 FR 25915). Once the common base year of 1995 was established for these source categories, the BEA growth assumptions utilized by OTAG were used to estimate the 2007 base case inventory.

1. Base Inventory

Comment: The majority of comments related to the non-EGU point source inventory alleged that these inventories were incomplete or inaccurate. The comments generally addressed missing sources, non-existent or retired sources, incorrect source sizes, mis-classification of processes, or emission allocation inconsistencies. Many of these commenters provided specific adjustments to be made to the inventories, including emissions modifications, activity factors, source sizes, and facility name changes. A number of States supplied completely new inventories to replace what was in the proposed data sets. Other commenters made broad, general categorical comment on the quality of the inventories with no supporting data.

Response: As was followed under the OTAG inventory update procedures, all State supplied comments were generally incorporated ''as is'' with the understanding that each State quality-assured its own data before submission. Industry-supplied comments were forwarded to respective State agencies for review and where data were deemed appropriate for inclusion, integrated into the inventories. In some instances, States responded that the data provided by the State should override that supplied by industry, or vice-versa. Comments were, in some cases, not incorporated when necessary to prevent double counting of emissions in point and area source inventories, where base year emission modifications were calculated from permitted emission levels and not actual operating activity, where additional supporting data could not be provided by the commenter, or where comments were general characterizations of inventories or inventory sectors. Note that even after State review, if the EPA felt that the data, procedures, methodologies, or documentation provided with the comment were not sufficient, valid, or justifiable, comments, or portions thereof, were excluded from the revision.

Both 1990 and 1995 base year emission and growth modifications were submitted and where 1990 data were provided, the methods described earlier in this Section were utilized to account for growth to 1995 and 2007 levels.

2. Growth

Comment: Several commenters suggest that the growth factors used to determine 2007 non-EGU point source base year inventories are inaccurate or inconsistent across regions and categories of the inventory. They explained that if growth factors are to be used to estimate future base year emissions, consistent national or region-wide values should be utilized for all categories across all States within the domain. This, they continue, would promote equitable potential progress to all areas and not penalize those that have shown past poor growth rates. Some commenters go on to state that growth rates based on past growth automatically disadvantage States which have suffered from unusually low growth rates. In addition to growth rates, some commenters provided 2007 base year emission estimates either with or without the growth and control information needed to validate their calculation.

Response: As noted above, EPA relied on BEA State-specific historical growth estimates of industrial earnings at the 2-digit SIC level as among the best available indicators of growth for non- EGU point sources. The BEA projection factors assume the continuance of past economic relationships. These factors are published every five years and adjusted to account for recent production and growth trends. For this reason, BEA data provide a useful set of regional growth data that EPA recommends for use in preparing emission inventory projections. It is true that BEA projection factors differ among different areas and different source categories because of historical differences in industrial growth among those different areas and source categories. However, in general, these projection factors offer the most reliable indicators of future growth as are available.

In cases where commenters questioned the use of EPA's growth rates but provided no alternative of their own, EPA had little choice but to continue to use the BEA-derived growth rates. Some commenters provided alternative or supporting information for modification of source category or State growth estimates. In those cases where a State or industry may have had more accurate information than the BEA forecast (e.g., planned expansion or population rates), data were verified and validated by the affected States and by EPA, and revisions were made to the factors used for that category.

3. Budget Calculation

Background: In the NPR and SNPR, EPA proposed that EGUs with a capacity less than or equal to 25 MWe or 250 mmBtu/hour would be considered small sources (''cutoff level'') and, as such, EPA would not assume an emissions decrease as part of the Statewide budget for this group of sources. At the same time, EPA proposed 2 cutoff levels for industrial (non-EGU) boilers and turbines: units with a capacity greater than 250 mmBtu/hour were defined as large units subject to a 70 percent emission reduction assumption; units with a capacity less than or equal to 250 mmBtu/hr but with emissions greater than 1 ton/day were defined as medium units subject to reasonably available

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control technology (RACT); and units with a capacity less than or equal to 250 MmBtu/hr and with emissions less than or equal to 1 ton per day were considered small sources for which no reduction would be assumed in the budget. In the SNPR, EPA specifically invited comment on the size cutoffs and on treating large industrial combustion sources (greater than 250 mmBtu or approximately 1 ton per day) at control levels equal to that for EGUs (63 FR 25909). As described below, this approach has been modified somewhat in response to comments and further analysis.

a. Proposed Control Assumptions.

Comments: Some comments supported EPA's proposed approach of assuming 70 percent and RACT controls in its calculation of the budgets. Numerous comments were received stating that the 70 percent reduction is inappropriate, may not be cost-effective and may not be achievable, especially for the following industries: cement plants; municipal waste combustors; certain pulp and paper operations, including lime kilns and recovery furnaces; glass manufacturing; steel plants; and some industrial boilers. Some comments suggested a control level of 60 percent rather than 70 percent. On the other hand, one commenter stated that SCR and SNCR are applicable and have been installed on hundreds of industrial sources.

Response: The EPA generally agrees that 70 percent emissions reduction is not appropriate for all large sources or all large source categories, even though SCR and SNCR are applicable and cost-effective for many sources. Instead of applying a one-size-fits-all percentage reduction to all large non-EGU sources, the specific emissions decreases assigned to each of these source categories for purposes of budget calculation in the final SIP Call rulemaking reflect the specific controls available for each source category that achieve the most emissions reductions at costs less than an average of $2,000 per ton. As described elsewhere in this notice, EPA's analysis results in calculating budget reductions ranging from 30 percent to 90 percent for several source categories and no controls to several other source categories.

b. Small Source Exemption.

Comments: In general, commenters were supportive of EPA including a cutoff level as part of the budget calculation; however, there were many suggestions on what the cutoff should be. The EPA received numerous comments supporting the proposed cutoff level of 25 MWe for EGUs, which is approximately equivalent to 250 mmBtu/hr or one ton per day. In addition, EPA received a few comments supporting a 250 mmBtu/hr cutoff for non-EGU point sources. Commenters indicated that the levels were appropriate and that it was important to be consistent with cutoff levels in the OTC's NO_X trading program. The Ozone Transport Commission (OTC) comprises the States of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia. In September 1994, the OTC adopted a memorandum of understanding (MOU) to achieve regional emission reductions of NO_X. These reductions are in addition to previous OTC state efforts to control NO_X emissions, which included the installation of reasonably available control technology. The OTC's NO_X trading program requires utility and nonutility boilers greater than 25 MWe or 250 mmBtu to reduce emissions in order to meet a NO_X budget and allows emissions trading consistent with that budget. These NO_X reductions will take place in two phases, the first phase beginning on May 1, 1999 and the second phase on May 1, 2003.

Some comments suggested assuming budget controls on units less than or equal to 25 MWe at RACT levels without a cutoff level. Others supported EPA's proposal of assuming no additional controls on these sources. Some comments suggested exempting medium-sized non-EGU sources.

Many commenters supported the general 1 ton per day exemption contained in the NPR and SNPR. However, a few comments suggested a more stringent cutoff level of 50–100 tons per year, similar to definitions of ''major source'' in the CAA. One commenter recommended a less stringent level of 5 tons per day cutoff level.

A few comments suggest using tons per day as the primary criterion to define large- and medium-sized non-EGU sources, rather than boiler capacity. This approach would exempt, for example, industrial boilers that exceed the 250 mmBtu capacity, but which emit less than one ton per day on average. The EPA's proposed approach considers a source large if heat input capacity data are available and exceed the 250 mmBtu capacity criterion, regardless of its average daily emissions. In support of this approach, commenters stated that industrial operations do not usually operate at or near capacity, while EGUs often do.

A few commenters indicated that the OTAG recommendations for turbines and internal combustion engines (in terms of horsepower cutoff levels) be used. OTAG had recommended cutoff levels of 4,000 horsepower for stationary internal combustion engines and 10,000 horsepower for gas turbines.

Response: For reasons described below and in the NPR (62 FR 60354), EPA believes that the cutoff levels of 250 mmBtu/hr and 1 ton per day for large non-EGU point sources are appropriate. The EPA selected 250 mmBtu/hr and 1 ton per day primarily because this is approximately equivalent to the 25 MWe cutoff used for the EGU sector. Emission decreases from sources smaller than the heat input capacity cutoff level, and that emit less than 1 ton of NO_X per ozone season day, are not assumed as part of the budget calculation; these sources are included in the budget at baseline levels.

The EPA believes that the 1 ton per day exclusion contained in the NPR and SNPR is appropriate and necessary. This level allows today's rulemaking to focus, for the purpose of calculating the budget, on the group of emission sources that contribute the vast majority of emissions, while at the same time avoids assuming emissions reductions from a very large number of smaller sources (as described in the following paragraph). In taking today's first major step towards reducing regional transport of NO_X, EPA does not believe that emission reductions from these small sources need to be assumed. This approach provides more certainty and fewer administrative obstacles while still achieving the desired environmental results. Although other cutoff levels were suggested by commenters, EPA believes that the cutoff levels described above strike the appropriate balance so that reasonable controls may be applied by States to a sufficient but manageable number of sources to efficiently achieve the needed emission reductions.

Most small sources emit less than 100 tons of NO_X per year. Although their total emissions are low, small sources account for about 90 percent of the total number of point sources. Thus, not assuming controls on these sources at the present time would greatly limit administrative complexity and reporting costs. This common-sense approach results in reducing the non-EGU population potentially affected by the ozone transport rule from more than 13,000 sources estimated in the NPR and SNPR to under 1,200.

Although a few comments suggested using tons per day, not capacity (MWe or mmBtu/hr), for setting cutoff levels, EPA chose primarily to use capacity indicators. This approach is consistent with the framework of the emissions trading program. In addition, EPA is concerned that units could have low average emissions during the ozone season but relatively high emissions on some high ozone days. Accordingly, EPA is relying on a capacity approach first and a tons per day approach second (where capacity data is not available or appropriate) to define units for which reductions are assumed in EPA's budget calculations.

As noted in the proposal notices, horsepower data was generally absent from the available emissions inventory data. Thus, the OTAG recommendation could not be used. Because quality assured data are still lacking, EPA used alternative approaches to determine size categories as described above. For the purposes of calculating the State budgets, the following approach is used to determine whether controls should be assumed on a particular source for the purposes of calculating the budget:

1. Use heat input capacity data for each source if the data are in the updated inventory.
2. If heat input capacity data are not available, use the default identification of small and large sources developed by EPA/Pechan for OTAG and also used to develop the NPR and SNPR budgets for source categories with heat input capacity fields (''default data'').
3. Emission reductions would be assumed if specific source heat input capacity data or default data indicate that a source is greater than 250 mmBtu/hr in the updated inventory.
4. If specific or default heat input capacity data are not available in the updated inventory (or not appropriate for a particular source category), emission reductions would be assumed if the unit's average summer day emissions are greater than one ton per day based on the updated inventory.
5. All others are ''small'' and no emission reductions are assumed.

c. Exemptions for Other Non-EGU Point Sources.

Comments: Several comments described source categories that might be excluded from being assigned assumed emissions decreases for purposes of calculation of the NO_X budgets. In the NPR, EPA assumed a 70 percent reduction from large sources and RACT on medium-sized sources. Some commented that it is not possible to control lime kilns and recovery furnaces or that potential NO_X emissions reductions are very small. One comment noted that recovery units typically emit at a rate of 0.15 lb/mmBtu or less and lime kilns at 0.20 lb/mmBtu or less and suggested establishing an emissions rate floor so that sources emitting less than 0.15 lb/mmBtu (or some other floor) would not need to further control. Other commenters suggested exempting cyclone boilers less than 155 MWe and all aircraft engine test facilities.

Response: The EPA agrees that for purposes of today's rulemaking the State budgets should not reflect assumed reductions in emissions from lime kilns, recovery units and aircraft engine test facilities. The amount of emissions from these source categories is very small relative to other point source categories considered in this rulemaking. Further, there is no experience in applying NO_X control technologies full scale to aircraft engine test cells in the U.S. (EPA–453/ R–94–068, October 1994).

The EPA acknowledges that NO_X controls may be available at costs less than $2,000 per ton for lime kilns, recovery units and aircraft engine test cells. However, these source categories include a relatively small number of sources with a small amount of emissions. The EPA is concerned that assuming controls on these sources for purposes of State budgets would encourage States to attempt to regulate these sources. The EPA believes State regulation could be inefficient because of the relatively high administrative costs of developing regulations for these few source categories (particularly for aircraft engine test cells because no regulations have been developed for this source category).

Similarly, EPA determined for each of the following non-EGU point source categories that the amount of emissions are small relative to the total non-EGU point source emissions and, thus, State regulation could be inefficient because of the relatively high administrative costs of developing regulations for these few source categories: ammonia, ceramic clay, fiberglass, fluid catalytic cracking, iron & steel, medical waste incinerators, nitric acid, plastics, sand/gravel, secondary aluminum, space heaters, and miscellaneous fuel use operations. Further, for many of these categories the number of sources is small and/or control technology information is limited (e.g., where an Alternative Control Techniques document does not exist for that category). The EPA believes that it would be an inefficient approach to suggest that States consider adopting emissions reduction regulations for each of these categories. Therefore, EPA did not calculate emissions reductions from these source categories for purposes of calculating the budget.

At this stage in the process to reduce regional transport, EPA considers it most efficient to focus State and administrative resources on the source categories with greater amounts of emissions. While States may choose to control any mix of sources in response to the SIP call, EPA is not, in today's rulemaking, assuming reductions from these source categories as part of the budget reduction calculation and does not believe it is necessary for States to do so.

It should be noted that EPA is generally treating the non-EGU boilers/turbines in the same manner as the EGUs to enable States that opt into a trading program to develop a simple and effective trading program. Thus, the size cutoffs discussed earlier in this section are identical. Further, the regulatory definition of a unit has been revised to make it clear that only fossil-fuel fired boilers and turbines are affected; this is discussed in detail in the trading program section later in today's notice. In addition, it should be noted that EPA is not excluding reductions from cyclone boilers, whether EGU or non-EGU, between 25–155 MWe from the calculation of the State budgets in this rulemaking. Such sources can be large emitters of NO_X and EPA expects the control costs will be less than $2000/ton on average through participation in the emissions trading program.

d. Sources Without Adequate Control Information.

Comments: As described in the SNPR, there are many sources in the emissions inventory which lack information EPA would need to determine potentially applicable control techniques. The SNPR proposed to leave these sources in the budget without assigning any emissions reductions. The EPA received comments that generally supported the SNPR approach not to assign emissions reductions to the diverse group of sources where the Agency lacked sufficient information to identify potential control techniques (63 FR 25909).

Response: This group of sources is diverse and does not fit within the categories set out by EPA, but total emissions are low for this group. The EPA believes that the effort needed to collect adequate information concerning controls for those sources (about 6,000 small and 260 medium or large) would be time consuming, the quality of the information may be uncertain, and it would potentially affect only a small amount of NO_X emissions. Therefore, for purposes of today's action, EPA continues not to assume decreases in emissions for these sources for purposes of calculation of the State budgets, but to keep them in the budgets at baseline levels. In the future, as more information becomes available, and if additional NO_X control is needed to further reduce ozone transport, further

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consideration of these sources may be necessary. Of course, States with adequate information may choose to control these sources to meet their budgets.

e. Case-By-Case Analysis of Control Measures.

Comments: Some commenters suggested that EPA simply assume reasonably available control technology (RACT) for medium and, in some comments, large sources in all upwind States on a case-by-case basis and assure that marginally stringent source-specific reduction levels are rejected. Many commenters stated that RACT default levels used by EPA were not sufficiently accurate and that case-by-case analysis was needed because every industrial source is different. Other comments generally stated that control level decisions should only be made on a case-by-case basis because each affected unit may have unique features that alter its cost-effectiveness.

Response: In the final budget calculation procedure EPA does not calculate RACT requirements for medium-sized sources. The assumption of RACT or other controls on industrial boilers and turbines between 100–250 mmBtu/hr would have been inconsistent with EPA's approach for utility boilers and turbines, which exempts units less than or equal to 250 mmBtu/hr. To be consistent with the way EPA treats EGUs and because data is often lacking for the smaller size sources, EPA redefined ''affected'' non-EGU units to primarily include those greater than 250 mmBtu. In cases where heat input data are not available, affected non-EGU units are those greater than 1 ton per day; this level is also consistent with the EGU cutoff because it is approximately equivalent to the 250 mmBtu level. Consistency with the EGU approach is important because it provides equity, especially among the smaller boilers and turbines and simplifies the model trading program. Therefore, the final rule does not calculate budget reductions for the medium size non-EGUs.

For the above reasons and as described below, EPA has examined the non-EGU sources on a category-by-category basis and determined appropriate control level assumptions for the large units. There are several reasons why EPA did not choose to calculate the budget by examining sources on a case-by-case basis. First, such an approach would be inefficient since all large sources would need to be examined, rather than some source categories being eliminated due to category specific cost-effectiveness limitations or amount of emissions. Second, it would be very difficult for the States to complete a case-by-case analysis of their large sources, develop rules, and respond to the SIP call within the 12 month time frame (or the statutory maximum 18 months). States needed much more time to respond to a similar requirement, the 1990 CAA NO_X RACT program. The CAA allowed a 2-year period before the NO_X RACT rules were due from the States; however, few States met this time frame and several adopted generic RACT rules which, in practice, resulted in much longer time frames before the case-by-case RACT analyses were completed and State rules adopted. Third, the option of participating in a trading program should mitigate cost impacts on some sources that may have unique configurations or other constraints. Fourth, EPA has often issued standards on a category-wide basis (e.g., New Source Performance Standards) which have proved workable even though some individual units have higher costs than the average. Fifth, the results of such case-by-case analyses may not be perceived to be as equitable as the categorical approach because the control levels resulting from the case-by-case approach are likely to vary from source- to-source and State-to-State. Finally, the category-by-category approach selected by EPA is preferred because it will achieve air quality benefits sooner than the case-by-case approach.

f. Cost-Effectiveness.

Comments: The EPA received numerous comments on cost-effectiveness. Those comments related to uniform control levels or cost per air quality improvement are addressed elsewhere in this notice. Some comments supported EPA's proposed $2,000 per ton approach. Some commented that EPA should use incremental costs, which are the costs and reductions associated with obtaining further control from a unit that already has some level of controls installed. Several commenters suggested using marginal costs, defined as the cost of the last ton of NO_X removed by a control strategy. Many stated that the costs for non-EGUs should be no greater than for utilities on a $/ton basis. One commenter noted that non-EGU costs will be considerably lower than EPA estimates. One comment suggested that EPA assume no further controls if the source has BACT, LAER, MACT or RACT already in place. One comment supported a command-and-control approach instead of the least cost for the non-EGUs, and asserted that controlling 13,000 sources through this rulemaking may not be feasible. Several commenters suggested that CEMS costs for non-utilities should be included in the cost-effectiveness determinations and that alternative monitoring methodologies should be considered.

Response: The EPA believes that the approach of average cost-effectiveness described in the proposal notices is appropriate for this rulemaking. In establishing the upper limit of the cost- per-ton range that EPA considers highly cost-effective for this rulemaking, EPA relied on average cost-effectiveness values estimated for recently proposed or promulgated rulemakings. The marginal cost-effectiveness for the level of control decided upon in the other programs and rulemakings was not always estimated or readily available. The EPA's latest assessment of cost-effectiveness does account for the level of existing or planned control in the baseline case. Therefore, when EPA refers to average cost-effectiveness it is the average incremental cost between the base and the more stringent level of control.

For the non-EGU point sources, in the NPR and SNPR EPA had aggregated the non-EGUs as one group, which meant that a few source categories with relatively low costs and high percentage emissions decreases dominated overall average cost-effectiveness. For today's final action, EPA revised its approach and analyzed individual source categories to determine if control techniques are available at average costs less than $2,000 per ton. Further, EPA included in this cost-effectiveness approach the costs related to CEMS, because this is a new and potentially high cost to some of the non-EGU source categories. As described in the RIA that supports this final rulemaking, EPA's analysis determined that the following non-EGU source category groupings could achieve substantial emissions decreases at average costs less than $2,000 per ton: industrial boilers and turbines, stationary internal combustion engines, and cement manufacturing. As further described in the RIA, controls for sources grouped in the following categories exceed $2,000 per ton: glass manufacturing, process heaters, and commercial and industrial incinerators.

The EPA believes that, over time, costs for non-EGU point sources will be lower than current EPA estimates; however, the changes cannot be quantified at this time. As discussed below, EPA agrees that one source category that has a NO_X standard set through the MACT process should not be assumed to implement further controls.

g. Industrial Boiler Control Costs.

Comments: Several comments were submitted indicating that industrial

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boiler costs are generally higher than utility boiler costs. The comments cited factors of load variability, smaller size/ economies of scale, firing of multiple fuels, and the ability to finance new controls and pass on costs. Some comments stated that most industrial boilers are one-seventh the size of utilities and, thus, EPA should recognize that the costs of controls would generally be higher due to economies of scale.

Response: The EPA agrees that industrial boiler sources are generally smaller than utility boiler sources; however, some individual industrial sources are larger than some utility sources. The EPA agrees that costs, on average, to the industrial sector are expected to be somewhat greater than that expected by the utilities due, in part, to economies of scale and the need for CEMS (which are already in place at utilities). Primarily due to the costs related to continuous emissions monitoring systems, EPA's reanalysis of cost-effectiveness for industrial boilers resulted in a control level of 60 percent, which is less stringent on average than that for utilities.

h. Cement Manufacturing.

Comments: In the NPR, EPA proposed a 70 percent control assumption on large sources and RACT on medium sources, including cement plants. Some commenters suggested that cement manufacturing should be excluded because in the SIP Call area, there are only a few cement plants and they have low emissions. Several commenters noted that many cement plants had already implemented NO_X RACT controls. Some comments disagreed with the costs and controls contained in EPA's Alternative Control Techniques document (EPA–453/R–94–004, March 1994) and added that EPA should not assume the same controls for different types of cement plants. Several commenters stated that 70 percent control is not feasible and SCR costs would be greater than $4,500 per ton, but that 20–30 percent control is possible. One commenter stated that the SIP call would provide a major competitive advantage to plants outside the region, and that multi-plant companies may shut down facilities inside the SIP call region and increase output at plants outside.

Response: Over 50 cement manufacturing units together emit more than twenty percent of emissions from large point sources not in the trading program (about 40,000 tons per season). The EPA believes that the emissions from this one industry are sufficiently high that it is appropriate to examine the availability of cost-effective controls.

The cost and control estimates in the Alternative Control Techniques (ACT) document were peer reviewed and, as such, are considered by EPA as the best data available. Consistent with the ACT document for this industry, EPA generally agrees with the commenters that a 70 percent control level would exceed the $2,000 per ton level used as EPA's cost-effectiveness framework. But, with the evidence cited in the cement ACT document and in some comments, EPA believes that a 30 percent reduction from uncontrolled levels would be within the cost-effectiveness range for reducing emissions at all types of cement manufacturing facilities. Therefore, the budget calculations assume a 30 percent control level for this source category. The EPA does not anticipate that, if States were to choose to apply a 30 percent control level to cement plants, this would be a major competitive disadvantage for plants located in the SIP call area because many cement plants in the region have already successfully implemented such controls in State RACT programs.

i. Stationary Internal Combustion Engines.

Comments: One comment suggested EPA set RACT levels at 25 percent for this category.

Response: As noted above, EPA is not using a RACT approach in the final rulemaking, but has examined each non-EGU point source category separately to determine the maximum available emissions reductions from controls that would cost less than $2,000 per ton on average. As described in the RIA, this process of looking at source categories individually resulted in EPA changing the control level assumption for this category from 70 percent in the NPR to 90 percent control in today's final rule. As described elsewhere in this notice, EPA also changed the control level assumptions for other source categories through this more detailed approach.

For this source category, EPA determined based on the relevant ACT document, that post-combustion controls are available that would achieve a 90 percent reduction from uncontrolled levels at costs well below $2,000 per ton. (EPA–453/R–93–032, 1993.) Therefore, the budget calculations include a 90 percent decrease for this source category from uncontrolled levels.

For spark ignited rich-burn engines, non-selective catalytic reduction (NSCR) provides the greatest NO_X reduction of all technologies considered in the ACT document and is capable of providing a 90 to 98 percent reduction in NO_X emissions. The control technique for spark ignited lean burn, diesel, and dual fuel engines is selective catalytic reduction (SCR). The SCR provides the greatest NO_X reduction of all technologies considered in the ACT document for these engines and is capable of providing a 90 percent reduction in NO_X emissions.

j. Industrial Boilers and Turbines.

Comments: Several commenters indicated that boilers using SNCR may achieve 40–60 percent reduction, but not 70 percent. Other comments supported the 70 percent control level proposed.

Response: The EPA examined the category of industrial boilers and turbines to determine the largest emissions reductions that would result from controls costing less than $2,000 per ton on average, including costs related to CEM systems. As described in the RIA, for this source category, EPA determined that controls, including SCR and SNCR, are available that would achieve a 60 percent reduction from uncontrolled levels at costs less than $2,000 per ton on average. For those sources that participate in the trading program, EPA believes that the costs would be further reduced. Therefore, the budget calculations include a 60 percent reduction for this source category from uncontrolled levels.

k. Municipal Waste Combustors (MWCs).

Comments: Several comments suggested that State budgets should not reflect emissions decreases for MWCs beyond those already required by the MACT rules.

Response: The NPR did not assume reductions for MWCs in the calculation of the budgets. However, since MACT reductions are required, and will be achieved well before 2007, those reductions should be accounted for in the 2007 baseline emissions inventory. The EPA agrees that additional emissions decreases beyond MACT levels are not warranted for this source category at this time because they would exceed the $2,000 per ton framework for highly cost-effective controls. Therefore, EPA has incorporated the NO_X emissions decreases due to the MACT requirements into the 2007 baseline levels and not assume any further reductions.

D. Highway Mobile Sources

Background: For the NPR and SNPR, highway vehicle emissions were projected to 2007 from a base year of 1990. The NPR used the 1990 OTAG inventory as its baseline. The 1990 OTAG inventory was based on actual 1990 vehicle-miles-traveled (VMT) levels for each State, based on State

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submittals to OTAG where available, or on historical VMT data obtained from the Highway Performance Monitoring System (HPMS) if State data were not available. The EPA proposed to switch to historical 1995 VMT levels from the HPMS; States were encouraged to submit their own 1995 VMT estimates where those estimates differed from HPMS.

In today's notice, EPA has implemented the changes it proposed in the NPR in calculating baseline and projected future NO_X emissions from highway vehicles. A 1995 baseline is used for today's notice in place of the 1990 baseline used in the NPR. The HPMS data were used to estimate States' 1995 VMT by vehicle category, except in those cases where EPA accepted revisions per the comments. These VMT estimates reflect the growth in overall VMT from 1990 to 1995, as well as the increase in light truck and sport-utility vehicle use relative to light-duty vehicle use. The 1995 NO_X emissions inventories also reflect the type and extent of inspection and maintenance programs in effect as of that year and the extent of the Federal reformulated gasoline program. The EPA is continuing to use the growth factors developed by OTAG for the purpose of projecting VMT growth between 1995 and 2007. These growth factors were revised with appropriately explained and documented growth estimates submitted during the comment period for the NPR.

The 2007 highway vehicle budget components presented in today's notice are based on EPA's MOBILE5a emission inventory model with corrected default inputs, which represents the most current EPA modeling guidance to States when developing their SIPs. [60]

1. Base Inventory

Comment: The EPA received a number of comments on baseline highway vehicle emission inventories. Most of these commenters proposed changes to baseline VMT estimates or to control factors related to highway vehicle emissions.

Response: In the NPR and SNPR, EPA asked commenters to provide sufficiently detailed information to permit revision to county-level emission inventories, in order to allow airshed modeling to be performed using the revised inventories. A number of proposed VMT revisions submitted by commenters were not sufficiently detailed to permit county-level inventory revisions and therefore these revisions were rejected. Other commenters provided sufficiently detailed data, which were incorporated into the base year VMT inventory, with two exceptions. Two States submitted 1995 VMT estimates that were inconsistent with EPA and U.S. Department of Transportation information on the relative contribution of light-duty trucks to total VMT. The EPA chose to use the HPMS default data for these two States.

Comment: One commenter asked the EPA to use VMT from the 1996 Periodic Emissions Inventory (PEI) or 1996 National Emissions Trends (NET), rather than 1995 Highway Performance Modeling System (HPMS) data when calculating baseline inventories. Several other commenters supported EPA's use of 1995 HPMS data to calculate baseline VMT inventories.

Response: Guidance on how to construct the 1996 PEI was not released until July 1998 and State PEI submittals are not expected until 1999. The EPA has determined for this reason that the 1996 PEI is not suitable for calculating the baseline VMT inventory. The EPA considered using 1996 NET VMT data in its base inventories, but those data were based on estimated 1995 HPMS inputs. The EPA has chosen to use the actual 1995 HPMS data rather than estimates in order to reduce the uncertainties associated with estimating baseline and 2007 emission inventories.

Comment: One commenter suggested using a multi-year VMT activity average to establish the highway emission baselines to smooth out abnormal patterns, instead of relying solely on 1995 activity.

Response: The EPA proposed using 1995 VMT in order to shorten the time period over which VMT growth would have to be projected. The EPA is not aware of any evidence that suggests that 1995 was an abnormal year in terms of VMT activity. Furthermore, States did not submit multi-year VMT averages in response to the EPA's invitation to submit their own VMT data. If the EPA were to construct multi-year averages, it is not clear what time frame would be appropriate. The EPA believes that the uncertainty related to having to project VMT growth estimates over a longer time period is at least as great as the uncertainty related to the representativeness of 1995 VMT. For these reasons, EPA has chosen to use 1995 VMT for base year and projection year inventories.

Comment: A number of commenters raised various issues about the use of the MOBILE5 emission factor model for this analysis. Most of these comments focused on specific assumptions or estimates incorporated in MOBILE5 which may need to be modified or updated to account for new information.

Response: The EPA is currently developing an updated emission factor model called MOBILE6. When final, this model will supersede the MOBILE5 model used by the EPA to develop baseline and 2007 emission inventories and States' highway vehicle budget components. The concerns raised by commenters are being evaluated as part of the MOBILE6 development process. At the present time, however, MOBILE5 remains EPA's official emission factor model. The EPA currently is not able to determine whether the highway vehicle emission modeling concerns raised by commenters are valid or whether the changes they suggest would raise or lower emission estimates; EPA is also not able to quantify the effects of commenters' concerns using its current emission models. Some of the changes EPA expects to make in its next official emission factor model, such as the effects of aggressive driving and air conditioner use, are likely to raise emission estimates; others, such as less-rapid deterioration of emissions performance than previously forecast, are likely to lower emission estimates. Because the overall effect of these and other changes cannot yet be determined, the EPA has chosen to continue using its current official emission model in today's action.

As discussed in Section III.F.5, the budgets presented in today's action serve as a tool for projecting in advance whether States have adopted measures that would produce the required amount of emissions reductions, as indicated by the initial demonstration submitted in September 1999. The budgets are also a means for determining from 2003 to 2007 whether States are fully implementing those measures. Thus, the budgets are an accounting mechanism for ensuring that the upwind States have adopted and implemented control measures that prohibit the significant amounts of NO_X emissions targeted by section 110(a)(2)(D)(i)(I). Although EPA's

[60] Both MOBILE5a and MOBILE5b are official EPA models. States can use either model in their SIPs, provided they use the corrected default inputs with MOBILE5a. For the control programs evaluated in today's action, MOBILE5a with corrected default inputs gives the same emission estimates as MOBILE5b. Because both models are considered valid by EPA and give the same emission estimates, the EPA has determined that the choice of which model to use in calculating highway vehicle emission budget components is a matter of convenience. The EPA has chosen to retain the use of MOBILE5a for today's action in order to maintain consistency with the OTAG process, in which MOBILE5a with corrected default inputs was used to construct its highway vehicle emission inventories and to calculate the effectiveness of highway vehicle emission control options.

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projections of emissions from highway vehicles will change as the Agency improves its emission models, these changes will not in and of themselves require changes in the actions States undertake to reduce ozone transport under today's action.

2. Growth

Comments: The EPA received numerous comments concerning its projection of States' 2007 highway vehicle budget components. In addition to the changes in baseline VMT discussed previously in Section III.D.1 of this notice, the EPA received from a number of States proposed revisions to VMT growth estimates and the effectiveness of emission control programs.

Response: In today's action, EPA has implemented the following changes it proposed in the NPR in calculating States' 2007 highway vehicle budget components. The EPA has used State projections of VMT growth from 1995 through 2007 for States that submitted appropriately explained projections of VMT growth from 1995 to 2007. For other States, EPA projected 2007 VMT levels from the 1995 baseline VMT levels using the OTAG projected growth rates.

As proposed in the NPR, neither the highway vehicle budget components nor the overall NO_X budgets promulgated in today's action alter the existing conformity process or existing SIPs' motor vehicle emissions budgets under the conformity rule. The EPA has determined that Federal agencies or Metropolitan Planning Organizations (MPOs) operating in States subject to today's action do not have to demonstrate conformity to the SIP Call budgets or the highway vehicle budget component levels used to calculate the budgets. However, areas will be required to conform to the motor vehicle emissions budgets contained in the attainment SIPs for the new eight-hour standard. For their attainment SIPs for transitional ozone nonattainment areas, States might seek to rely on the modeling performed for the SIPs submitted in response to today's action. To the extent that this occurs, the VMT projections and motor vehicle emissions inventories associated with today's action could have a role in the conformity process, beginning when transitional areas are designated and classified in 2000.

3. Budget Calculation

Background: The EPA proposed highway budget components based on projected highway vehicle emissions in 2007 from a base year of 1990, assuming implementation of CAA measures, such as inspection and maintenance programs and reformulated fuels, measures already implemented federally, and those additional measures expected to be implemented federally by 2007. The additional Federal measures included the National Low Emission Vehicle Standards and the 2004 Heavy-Duty Engine Standards. The emission effects of revisions to the Federal Emissions Test Procedure, which had also been promulgated in final form, were not reflected in the projected 2007 emissions presented in the proposal because neither the emissions that this measure is designed to control nor the reductions in those emissions expected from the test procedure revisions had been incorporated in the projected 2007 emission estimates or in peer- and stakeholder-reviewed EPA emission models. The proposal also did not incorporate any benefits from Tier 2 light-duty vehicle standards since the EPA had not yet proposed or promulgated regulations concerning the level and implementation schedule for Tier 2 standards. Seasonal emissions were calculated by estimating emissions for a specific weekday, Saturday and Sunday during the ozone season and multiplying by the number of days of each type in the ozone season. These estimates were based on temperatures and temperature ranges recorded for actual ozone episodes. In the NPR, EPA proposed to change this approach to substitute monthly average temperatures and temperature ranges for ozone episode-specific temperatures when constructing the 2007 budgets. The highway vehicle budget components presented in today's notice reflects this change.

Comment: A number of commenters suggested that the EPA change its assumptions regarding emission control programs from those used in the NPR. One commenter claimed that the NPR did not include a number of cost-effective highway and nonroad mobile source NO_X reduction programs in its budget calculations. Other commenters suggested that the EPA focus more on expanding the RFG and I/M programs, adopting gasoline sulfur controls, implementing a reformulated diesel fuel program, or implementing the Tier 2 program. Contrary to these positions, a number of commenters agreed with the EPA's decision not to assume any expansion of the RFG or I/M programs, while still other commenters argued that the EPA should not include the emission effects of gasoline sulfur controls or reformulated diesel fuel in its calculation of State NO_X budgets. One commenter suggested that the EPA change its NLEV phase-in assumptions to match the final NLEV agreement. One commenter asked EPA to include the effect of the recent Revised Federal Test Procedure rule, which is aimed at reducing excess emissions from aggressive driving or air-conditioner use, in its budget calculation.

Response: Both the NPR and today's action include those mobile source reductions which EPA has determined or proposed to determine are technologically feasible, highly cost-effective, and appropriate to implement on a national basis, and which have been promulgated in final form or are expected to be promulgated in final form before States are required to submit revised SIPs. The highway vehicle budget components include the emission reductions resulting from implementation of the NLEV program, including the phase-in schedule agreed to by the States, automobile manufacturers, and EPA. The highway budget components do not include the effect of Tier 2 light-duty vehicle and truck standards and any associated fuel standards since these standards have not yet been proposed.

The extent of the RFG and I/M programs was not assumed to change beyond that assumed for the NPR, except for those States who were able to demonstrate that the NPR's modeling assumptions did not conform to the State's SIP and did not reflect CAA requirements. As discussed elsewhere in today's notice and in the NPR, the NO_X reductions alone from these measures do not appear to be highly cost effective in all of the areas that would be subject to reduced budgets. Because these measures offer additional benefits beyond NO_X reductions, specific local areas may determine that these measures are appropriate and cost effective given their full range of benefits.

The baseline and budget calculations include neither the increased emissions from aggressive driving or air conditioner use, nor the reductions in those emissions resulting from the Revised Federal Test Procedure rule. These emission effects are not reflected in EPA's MOBILE5a model; they are being evaluated for inclusion in MOBILE6. While the EPA has developed a modified version of its MOBILE5 model to estimate these effects for its Tier 2 study, this modified model has not been used in any regulatory actions and is still subject to revision as part of EPA's model development process. As discussed above and in Section III.F.5. below, any

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changes by EPA in its emission models will not in and of themselves alter the emission reductions States must achieve to comply with the requirements of today's action.

Comment: One commenter suggested that the EPA not split VMT using weekend and weekday travel fractions when calculating monthly and seasonal total VMT. Another State commenter proposed an alternative method for calculating monthly and seasonal VMT from average daily VMT which did not rely on the EPA weekend/weekday travel fractions, but instead used monthly travel fractions specific to that State. Other commenters supported the weekend/weekday inventory modeling approach proposed by the EPA.

Response: The EPA and other organizations have amassed considerable evidence that weekend and weekday travel patterns differ significantly. The OTAG Final Report requested day-specific inventories for developing day-of-the-week activity levels used in emission inventory development and episode-specific modeling. Given this requirement, EPA has determined that the approach outlined in the NPR is appropriate and reasonable. The alternative method using State-specific monthly travel fractions as proposed by one State is a reasonable alternative. However, because EPA does not have the necessary information to apply this method to all other States, EPA did not incorporate this method in its analysis.

a. I/M Program Coverage.

Comment: One commenter urged the EPA to expand I/M programs to cover all urbanized areas with populations above 500,000 as recommended by OTAG. Other commenters also requested that EPA expand the I/M program or require specific States to adopt specific types of I/M programs. By contrast, other commenters supported the I/M approach taken by the EPA in the NPR.

Response: The OTAG recommended that States consider expanding I/M programs to cover all urbanized areas with populations above 500,000. The EPA has considered this recommendation but does not believe it to be appropriate to assume broader I/M implementation in calculating State budgets for the reasons outlined in the NPR (62 FR 60355). The State budgets promulgated in today's action reflect full implementation of I/M as required by the CAA and State SIPs.

b. Emissions Cap.

Comment: One commenter suggested that the EPA consider capping mobile source emissions, arguing that the proposed rule would place an undue burden on stationary sources.

Response: The State NO_X budgets promulgated in today's action include the projected emission benefits of those NO_X controls that the EPA has determined are technologically feasible and highly cost effective, as well as additional controls whose implementation is not dependent on this rule. While the EPA's analysis indicates that certain categories of stationary sources offer the potential for large, highly cost-effective NO_X emission reductions, the State NO_X budgets also reflect the emission effects of a number of mobile source controls (See Table IV–2). The EPA believes that it has applied its criteria for determining which controls to assume in State NO_X budgets equitably to both mobile and stationary sources. In contrast to EGUs and large non-EGUs, EPA has not concluded that a mass cap (which would effectively require offsets for VMT growth) is highly cost effective. For these reasons, EPA does not believe that today's action places an undue burden on any emission sector and does not believe that a separate cap on mobile source emissions is necessary.

c. Tier 2 Standards.

Comment: One commenter requested that EPA include the effects of Tier 2 light-duty vehicle standards when calculating State budgets if the NLEV program fails. Another commenter suggested that States not be permitted to adjust their budgets in case the NLEV program fails.

Response: This issue is not yet ''ripe'' because NLEV is currently being implemented and there are no signs that the program will fail. The EPA will consider whether to adjust State budgets if automakers representing a significant portion of new vehicle sales withdraw from the NLEV program, as discussed in Section III.F.5.

d. Low Sulfur Fuel.

Comment: One commenter stated that the EPA disregarded OTAG's call for reducing sulfur levels in fuel, which would have the effect of reducing NO_X emissions.

Response: The EPA's proposed rule and other actions match the OTAG recommendations on fuels, contrary to the commenter's suggestion. The OTAG gasoline recommendation stated, ''The USEPA should adopt and implement by rule an appropriate sulfur standard to further reduce emissions and assist the vehicle technology/fuel system [to] achieve maximum long term performance.'' It did not request that EPA implement a specific sulfur reduction proposal. The EPA is evaluating the costs and benefits of reducing gasoline sulfur levels as part of its proposed rulemaking to implement Tier 2 light-duty vehicle and truck standards. The EPA is also evaluating the relationship between diesel fuel standards and the emission standards as part of (i) its 1999 technology review for its 2004 highway heavy-duty diesel engine standards and (ii) its 2001 technology review for the Tier 3 and Tier 2 nonroad diesel engine standards. Until these evaluations are complete, EPA believes it is premature to assume any changes in fuel properties when calculating States' highway vehicle budget components.

e. Conformity.

Comment: One commenter recommended that NO_X transportation conformity waivers should lapse in the wake of today's action.

Response: Conformity waivers were granted on an area-by-area basis, given the facts of the situation in each local area. Any withdrawal should be based on similar local analysis, or upon submittal of a valid attainment plan. Today's action is not based on this kind of local analysis. Thus, there is no basis for any withdrawal of existing NO_X transportation conformity waivers. Furthermore, any such withdrawal would not alter the Statewide NO_X budgets set forth in today's action. For these reasons, the EPA has concluded that today's action does not alter existing conformity requirements, including any NO_X conformity waivers.

Comment: One commenter expressed concern that if current conformity budgets do not incorporate the same control assumptions as the States' budgets submitted in response to today's rulemaking, the growth in areas currently subject to conformity budgets could threaten the ability of States to meet the SIP call budgets. The commenter continued that failure to tie conformity budgets to transport budgets would allow these areas to grow to pre- SIP call control budget levels that could cause an exceedance of the Statewide budget. The commenter also stated that to address local ozone problems, transportation conformity plans should reflect the mobile source controls assumed in the SIP call.

Response: Conformity budgets cannot be tied directly to the SIP Call budgets because the latter are statewide and the former are nonattainment-area-specific. The Statewide NO_X budgets will be enforced as described in today's action, regardless of the conformity budgets in specific areas within the affected States. These budgets should reflect the actual level of motor vehicle emissions which States expect to occur.

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As noted elsewhere in this section, conformity budgets will reflect the mobile source controls assumed in the SIP Call budgets to the extent that the attainment SIP ultimately relies upon those controls. Today's action does not change the rules governing generation and use of emission reduction credits to offset further growth in the transportation sector as part of a local area's conformity demonstration.

E. Stationary Area and Nonroad Mobile Sources

Background: The EPA developed the NO_X SIP call emissions inventory for area and nonroad mobile sources based on data sets originating with the OTAG 1990 base year inventory. These base year inventories were prepared with 1990 State ozone SIP emission inventories supplemented with either State inventory data, if available, or EPA's National Emission Trends (NET) data if State data were not available. The OTAG 1990 nonroad emission inventories were based primarily on estimates of actual 1990 nonroad activity levels found in the October 1995 edition of EPA's annual report, ''National Air Pollutant Emission Trends.'' In the NPR, EPA proposed switching to EPA's 1997 ''Trends'' estimate of 1995 nonroad activity levels.

For the SNPR, area and nonroad mobile source inventory data for 1990 were then grown to 1995 using Bureau of Economic Analysis (BEA) historical growth estimates of industrial earnings at the State 2-digit Standard Industrial Classification (SIC) level. Because BEA data are historical documentation of industry earnings, EPA considered these to be among the best available indicators of growth between 1990 and 1995 (63 FR 25915). Once the common base year of 1995 was established for these source categories, BEA growth assumptions utilized by OTAG were used to estimate the 2007 base case inventory.

1. Base Inventory

Comment: The EPA received several comments on baseline area and nonroad mobile source emission inventories. Several commenters submitted estimates of their 1990 nonroad activity levels that differed from NPR estimates. One commenter provided statewide 2007 base year emissions estimates for numerous area source categories, while others provided similar information for 1990 or 1995 emission estimates. Many commenters expressed concern with existing area source inventory estimates and provided revised county-level area source inventories. One commenter suggested using a multi-year activity average to establish the nonroad emission baseline, arguing that a multi-year average would provide a more representative baseline than would a single year's data alone.

Response: In the NPR and SNPR, EPA asked commenters to provide sufficiently detailed information to permit revision to county-level emission inventories, in order to allow airshed modeling to be performed using the revised inventories. Some proposed area and nonroad inventory revisions submitted by commenters were State-wide revisions and did not contain sufficient detail to permit the EPA to revise county-level nonroad emission inventories. Because the EPA could not use these submittals to revise the county-level inventories used as inputs to its air quality modeling analyses, these submittals were not accepted. Other commenters did provide sufficiently detailed data, and EPA revised the appropriate emission inventories to reflect the commenters' estimates. These revised inventories were then grown to 1995 using BEA- derived growth factors, as described above.

Although EPA proposed in the NPR to switch to a 1995 inventory in calculating baseline NO_X emissions from nonroad mobile sources, EPA has chosen not to do so in today's action. Using the 1995 inventory presented in the ''Trends'' report as the baseline for today's action would have required the use of geographic allocation methods that have not undergone peer review and have not been made available for public comment by affected interests. The EPA has concluded that the use of these unreviewed methods in today's action would have deprived stakeholders of adequate opportunity to review, understand, and comment on their baseline inventories and the methods used to construct them. Hence, EPA has chosen to retain the 1990 baseline inventories for nonroad mobile sources presented in the NPR for today's action, with the changes made in response to comments.

As discussed above, EPA has chosen to use 1990 nonroad activity level estimates as the basis for its nonroad inventory projections. The EPA is not aware of any evidence that suggests that 1990 was an abnormal year in terms of nonroad activity. Furthermore, States did not submit multi-year nonroad activity averages in response to EPA's invitation to submit their own nonroad activity data. If EPA were to construct multi-year averages, it is not clear what time frame would be appropriate. To reduce the impact of unusual years, EPA would have to take a long-term average. However, doing so would require EPA to use an even earlier year as its base year for nonroad activity and inventory projections. The EPA believes that the uncertainty related to having to project nonroad activity growth estimates over a longer time period is at least as great as the uncertainty related to the representativeness of 1990 nonroad activity.

2. Growth

Comment: Several commenters suggest that the growth factors used to determine 2007 stationary area and nonroad mobile source base year inventories are inaccurate or inconsistent across regions and categories of the inventory. They explained that if growth factors are to be used to estimate future base year emissions, consistent national or region-wide values should be utilized for all categories across all States within the domain. This, they continue, would promote equitable potential progress to all areas and not penalize those that have shown past poor growth rates. Some commenters go on to state that growth rates based on past growth automatically disadvantage States which have suffered from unusually low growth rates. In addition to growth rates, some commenters provided 2007 base year emission estimates either with or without the growth and control information needed to validate their calculation.

Response: As noted above, EPA relied on BEA State-specific historical growth estimates of industrial earnings at the 2-digit SIC level as among the best available indicators of growth for stationary and nonroad area sources. BEA projection factors assume the continuance of past economic relationships. These factors are published every five years and adjusted to account for recent production and growth trends. For this reason, BEA data provide a useful set of regional growth data that EPA recommends for use in preparing emission inventory projections. It is true that BEA projection factors differ among different areas and different source categories because of historical differences in industrial growth among those different areas and source categories. However, in general, these projection factors offer the most reliable indicators of future growth as are available.

In cases where commenters questioned the use of EPA's growth rates but provided no alternative of their own, EPA had little choice but to continue to use the BEA-derived growth rates. Some commenters provided alternative or supporting information for modification of source category or State

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growth estimates. In those cases where a State or industry may have had more accurate information than the BEA forecast (e.g., planned expansion or population rates), data were verified and validated by the affected States and by EPA, and revisions were made to the factors used for that category.

3. Budget Calculation

Background: The EPA proposed nonroad mobile source budget components based on projected nonroad mobile source emissions in 2007 from a base year of 1990. These projections were developed by estimating the emissions expected in 2007 from all nonroad engines, assuming implementation of those measures incorporated in existing SIPs, measures already implemented federally, and those additional measures expected to be implemented federally. The additional Federal measures include: the Federal Small Engine Standards, Phase II; Federal Marine Engine Standards (for diesel engines of greater than 50 horsepower); Federal Locomotive Standards; and the Nonroad Diesel Engine Standards. In the NPR, EPA used the estimates developed by the OTAG for nonroad mobile source baseline emissions and growth rates.

Comments: The EPA received comments to use a State-specific set of growth rates for nonroad mobile source emissions.

Response: The EPA has used State estimates of 1990 nonroad activity levels and growth rates for 1990 through 2007 received during the comment period to revise its estimates of nonroad NO_X emissions in 2007, where those State estimates were appropriately explained and documented. For other States, the EPA has retained the baseline activity levels and growth rates used in the NPR, which in turn were based on the growth rates developed for OTAG.

F. Other Budget Issues

1. Uniform vs. Regional Controls

Background: In the NPR, EPA bases the State budgets upon assumed application of reasonable, highly cost-effective NO_X control measures. These measures were uniform across the 23 affected jurisdictions. They consisted of 0.15 lbs/MmBtu for the EGU sector; and 70 percent control for large, and RACT for medium-sized, non-EGU point sources.

Comments: A number of commenters opposed calculating budgets based on uniform emissions reductions and cited the fact that OTAG recommended a range of control levels. These commenters offered no specific alternatives, such as varying the assumed control levels by State or by groups of States, or alternative methods for determining different control levels. Numerous comments were received supporting the proposed uniform level of emissions reductions.

Response: The EPA has determined that each of the 23 jurisdictions has sources that emit NO_X in amounts that significantly contribute to downwind nonattainment problems. Moreover, EPA has determined that specified levels of control on certain sources in all of the jurisdictions would be highly cost-effective. This analysis applies with equal force to each of the 23 jurisdictions. It may be that emissions from some States have greater ambient impact on downwind nonattainment areas than emissions from more distant States. Even so, each of the States' NO_X emissions have a sufficient ambient impact downwind to conclude that those amounts are significant contributions and that NO_X emissions from all the upwind jurisdictions collectively contribute significantly to nonattainment downwind. Differentiating the contributions of individual upwind States on multiple downwind nonattainment areas is a highly complex task. The contributions of individual States are likely to vary from downwind area to downwind area, from episode to episode, and from NAAQS to NAAQS. Accordingly, it would be extremely complex to develop a budget for each State that would reflect the different impacts of its sources' emissions on different downwind States.

Among many factors that EPA considered in weighing whether to finalize a uniform control level or regional control levels in calculating States' emission budgets was the concern that different controls in one part of the SIP call area in combination with an interstate emissions trading program may lead to increases in pollution within areas having more restrictive controls. That is, if unrestricted interstate emissions trading were allowed on an one-for-one basis, emissions reductions might be expected to shift away from States assigned more restrictive controls to States which received less restrictive control requirements due to the lower control costs likely to exist in States with less restrictive controls. This may result in emissions above the budget level in areas with more restrictive controls.

There are two alternatives for addressing the problem of shifting emissions. The first is to allow trading only within uniform control regions, but not between regions with NO_X budgets reflecting different levels of control. The advantage to this approach is that it provides a straightforward way of preventing trades of excess emissions into regions with more stringent standards. However, a trading program that covers a smaller market area will provide less flexibility and reduce the possible savings for the affected sources as compared with larger trading programs. The second alternative is to establish a trading ratio for trades between regions, to reflect the differential impact of the emissions on nonattainment. The trading ratio should reflect the relative contribution of emissions to downwind non-attainment problems. The advantage to this approach is that it provides the flexibility for trades between regions when the benefits of such trades are large, while discouraging a shift of excess emissions into regions with more stringent standards. However, none of the comments on the proposal included a justification or description for trading ratios, which would reflect the differential environmental implications and discourage inappropriate shifting of excess emissions.

The ozone problem in the Eastern United States is the result of a large number of different types of sources which affect widely distributed nonattainment areas at different times under changing weather patterns such that a broadly-established control program is necessary. The EPA believes a reasonable strategy is to apply the most cost-effective control strategies uniformly in contributing States in order to eliminate the combined significant contribution from these multiple sources in multiple States.

The EPA analyzed costs and air quality benefits for two regional control level options that were based on a varying level of controls in different parts of the 23 jurisdictions. The analysis did not show that these two regional control alternatives would provide either a significant improvement in air quality or a substantial reduction in cost. An analysis of the costs and benefits of different control options can be found in the docket. On the basis of the analysis, EPA believes an alternative approach with differentiated NO_X budgets and regionally differentiated trading would not yield significant additional air quality benefits or cost savings vis a vis a regionwide trading program based on uniform NO_X budgets.

2. Seasonal vs. Annual Controls

Comments: One commenter suggested that controls should be required for the

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entire year rather than just during the 5-month ozone season as proposed.

Response: The EPA recognizes that control of nitrogen oxide emissions would likely produce non-ozone benefits, as well as ozone benefits. For example, NO_X control would likely reduce surface water acidification or eutrophication of surface waters. Annual control of NO_X may have a greater impact on winter and spring NO_X emissions, and therefore on acidification and eutrophication, than ozone season (summer) NO_X control to the extent that acidification and eutrophication result from the release of nitrogen compounds from snowpack during snowmelt and rain in the spring. Control of NO_X emissions also reduces fine particulates and regional haze, so that annual control of NO_X emissions would result in greater non-ozone benefits. However, the commenter's suggestion that EPA analyze the costs of, and assume in calculating the budgets, annual NO_X control to address non-ozone problems is outside the scope of this rulemaking proceeding. Here, EPA has proposed a NO_X SIP call to address the failure of certain SIPs to prohibit sources from emitting NO_X in amounts that contribute significantly to nonattainment (or interfere with maintenance of attainment) of the ozone NAAQS during the ozone season.

In analyzing the benefits of ozone season NO_X control under the proposed NO_X SIP call for purposes of the RIA (though not as a basis for the decisions in today's rule), EPA considered both the ozone and non-ozone benefits. Non-ozone benefits include the impact of ozone season NO_X control on acidification and eutrophication. In particular, emission modeling performed by EPA indicates that the SIP Call would reduce wintertime NO_X emissions. This results in part because, once installed to comply with the NO_X SIP call, some NO_X control systems (e.g., low NO_X burners which alter the combustion process and cannot simply be turned off) would reduce emissions throughout the year, even though the NO_X limits would be seasonal. Also see Section IX.

3. Full vs. Partial States

Background: In the NPR, the Agency indicated it was proposing to include entire States rather than exempting portions of States in the development of emissions budgets. The Agency's decision to include full States was based upon three major points: (1) The division of individual States by OTAG was based, in part, on computational limitations in OTAG's modeling analyses; (2) the additional upwind emissions from full, as opposed to partial, States would provide additional benefit to downwind nonattainment areas; and, (3) Statewide emissions budgets create fewer administrative difficulties than a partial-State budget.

Comments: During the two comment periods, 43 comments were received which specifically addressed some or all of the major points outlined above. The underlying theme throughout the comments on this issue was that the States and EPA had undertaken a comprehensive, scientifically credible modeling/analysis study during the OTAG, and that the Agency should follow OTAG's recommendations on this issue (i.e., allow for partial-State emission budgets). Another common theme was that the administrative difficulties outlined by the Agency in the NPR were exaggerated, and that the affected States should be allowed to generate partial-State, as opposed to statewide, emissions budgets, if their State considered it feasible to do so. Comments were received that portions of Alabama, Georgia, Michigan, Missouri, North Carolina, and Wisconsin should be excluded from the SIP Call.

Response: The underlying concepts for responding to these comments are (a) that the atmosphere is constantly in motion and has no limitations at geo-political boundaries, and (b) that the larger the geographic area that is controlled, the greater the downwind benefits. For the States requesting partial-State emissions budgets, there are NO_X emissions throughout these entire States. The EPA did State-specific modeling for each of the affected States, and these additional modeling analyses support the concept of statewide emissions budgets for each of the affected States. Furthermore, it is a reasonable assumption, given the nature of ozone chemistry, that if emissions from part of a State contribute significantly to downwind nonattainment or maintenance problems, emissions from the entire State contribute significantly to downwind nonattainment or maintenance problems. In each of the affected States, there is no peculiar meteorological phenomenon that would indicate that emissions from some portion of that State would not impact downwind nonattainment or maintenance problems. Thus, based on additional EPA modeling analyses and their technical interpretation, EPA is not promulgating partial-State emissions budgets. Since each State has the flexibility to determine which sources to control in order to meet the budget, a State can structure its control strategy to require fewer reductions in certain portions of the State and greater controls in other areas, as long as the significant amounts of emissions are eliminated.

4. NO_X Waivers

Comments: The EPA received several comments supporting the approach outlined in the NPR in which EPA would treat areas that had previously received NO_X waivers under section 182(f) of the CAA in the same manner as other areas in the SIP call. The comments stated that (1) special treatment (i.e., higher budget) for the waiver areas would increase the burden on downwind States; (2) numerous modeling efforts, including OTAG's, have shown that such disbenefits are generally minor and occur on days with low ozone concentrations; (3) disbenefits are small when upwind NO_X reductions are modeled; (4) disbenefits are better addressed at the local level; and (5) States already have the flexibility to deal with NO_X disbenefits, if any, through the budget and trading by meeting the budget through NO_X emission decreases in other areas of the State or acquiring allowances through trading. In addition, some commenters requested EPA to revoke waivers previously granted. Commenters also noted that the localized disbenefits are no less of a problem in the Northeast than in the Midwest.

Numerous comments were also submitted which oppose the approach outlined in the NPR. The comments generally stated that in States with NO_X waiver areas, the NO_X budget should be increased where NO_X decreases lead to ozone increases; otherwise States might seek reductions disproportionately outside the sensitive areas, resulting in cost-effectiveness levels greater than the $2000 per ton framework described in the SIP call proposals. Comments referred to disbenefits in Cincinnati, Louisville and the Chicago/Gary areas. Many commenters suggested that EPA wait for further modeling analyses to be completed and that the zero-out runs are inappropriate for evaluating the NO_X disbenefit issue. Some stated that the NO_X budget might interfere with local attainment and harm local public health. Other comments recommended that EPA consider the impact of additional VOC costs that might be needed to offset local ozone increases.

Response: In today's final rulemaking, EPA is setting NO_X emissions budgets for each of the jurisdictions affected by this action. These budgets are set in the same manner for areas without NO_X waivers as areas with NO_X waivers, except in the case of NO_X waivers granted for I/M programs. Although adverse comments were submitted, none of them provided any modeling analysis or support documentation showing how a State or States with NO_X waiver areas should be assigned a larger budget or proposing a specific alternative approach for assigning those budgets. In contrast, modeling described by EPA in the NPR and SNPR as well as additional modeling conducted by the Agency and some commenters continues to show that the benefits of NO_X emissions decreases greatly outweigh any disbenefits. These findings are discussed in Section IV, and summarized below.

The EPA considered the strengths and limitations in the commenters' modeling analyses in evaluating whether the technical evidence presented in the comments supports the arguments made by the commenters. The EPA's review of the commenters' modeling indicates that in general (a) downwind ozone benefits increase as greater NO_X controls are applied to sources in upwind States, (b) the net benefits of NO_X control at the level of the SIP Call outweigh any local disbenefits, and (c) upwind NO_X reductions tend to mitigate local disbenefits in downwind areas.

One commenter, the Lake Michigan Air Director's Consortium (LADCO), submitted air quality modeling directed toward investigating the disbenefits in nonattainment areas around Lake Michigan due to the NO_X controls in the SIP Call proposal. The commenter's general finding was that the greatest ozone decreases with these NO_X controls occur on high ozone days, while the greatest disbenefits occur on low ozone days. The EPA concurs with this finding, based on a review of the technical information provided by the commenter. Specifically, there were no predicted increases in ozone (i.e., disbenefits) in peak 1-hour ozone on any of the 4 days modeled by LADCO that had daily maximum 1-hour concentrations >=125 ppb in the Base Case. Also, on the 3 low ozone days which had predicted disbenefits, the increases were not large enough to result in a peak value >=125 ppb. Concerning 8-hour concentrations, only 1 of the 9 days with a predicted 8-hour daily maximum concentration >=85 ppb had an increase in peak ozone due to the SIP Call NO_X controls. Also, there was a small disbenefit on the one day modeled which had an 8-hour daily maximum concentration <85 ppb, but the magnitude of the disbenefit on this day was relatively small and did not cause the 8-hour peak value to exceed 85 ppb. Thus, based on this evaluation, EPA generally found that the submitted modeling did not refute the overall conclusions EPA has drawn concerning the impacts of NO_X emissions in the relevant geographic areas.

As described in the NPR, the OTAG process included lengthy discussions on the potential increase in local ozone concentrations in some urban areas that might be associated with a decrease in local NO_X emissions. The OTAG modeling results indicate that urban NO_X emissions decreases produce increases in ozone concentrations locally, but the magnitude, time, and location of these increases generally do not cause or contribute to high ozone concentrations. That is, NO_X reductions can produce localized, transient increases in ozone (mostly due to low-level, urban NO_X reductions) in some areas on some days, but most increases occur on days and in areas where ozone is low. In the SNPR, EPA documented the estimated ozone benefits of the proposed Statewide NO_X budgets based on an air quality modeling analysis. The major findings of that analysis include: Any disbenefits due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the air quality benefits expected from these budgets.

The results of EPA's assessment of the comments and available modeling corroborate and extend the findings presented in the SNPR. Thus, with respect to regional ozone transport and today's final action, EPA believes it is not appropriate to give special treatment to areas with NO_X waivers.

Several nonattainment areas in the 23 jurisdictions were granted waivers from certain NO_X requirements in past rulemaking actions. In the **Federal Register** notices granting the waivers, EPA stated that the continued approval of these waivers is contingent on the results of the final ozone attainment demonstrations and plans (See 61 FR 2428 January 26, 1996, LADCO). The attainment plans will supersede the initial modeling information which was the basis for waivers EPA granted (e.g., the LADCO waiver). The attainment plans were due in April 1998 and were to incorporate the results of the OTAG process. The EPA's rulemaking action to reconsider the initial NO_X waiver may occur simultaneously with rulemaking action on the attainment plans. Therefore, as these new modeling analyses are submitted to EPA, they will be reviewed to determine if the NO_X waiver should be continued, altered, or removed.

As discussed above, EPA has accounted for the continued presence of NO_X waivers for I/M programs in modeling States' NO_X budgets. Historically, EPA gives States considerable latitude in designing their I/M programs. This latitude is granted in recognition of the unique economic and air quality circumstances faced by each State. States have used this latitude to develop a range of I/M program designs. Some States have adopted EPA-recommended enhanced I/M programs; other States have adopted different I/M program designs.

The EPA acknowledges that some of the States granted NO_X waivers may be able to modify their programs to obtain NO_X reductions at minimal cost. However, some of the States which have been granted an I/M NO_X waiver have developed unique I/M program designs in terms of the model years covered, the emission testing equipment used, and possibly the number, location, and design of the testing and repair stations. The cost for these States to modify their I/M programs to obtain NO_X reductions are likely to exceed the level that EPA has determined to be highly cost-effective for the purpose of reducing ozone transport. As a result, the EPA has chosen to not include additional emissions reductions due to I/M NO_X programs when calculating NO_X budgets.

5. Recalculation ofBudgets

In the NPR, the EPA made proposals concerning what would happen if additional information becomes available after EPA's final rulemaking action. Examples of such information might include: (a) Source-specific information useful in determining RACT, (b) revised growth or other assumptions, (c) revised models and inventory estimates, (d) unexpectedly low implementation rates for NLEV, and (e) other new federal measures, i.e. Tier 2 controls. In the Recalculation of Budgets Section of the NPR, EPA proposed that if additional data become available after EPA's final rulemaking action, such data could be considered prior to State submittal of revised SIPs. The EPA asked for comments on this approach.

Most of the comments received were in favor of allowing States to adjust their emission budgets based on the most recent available data on emissions and RACT levels. There were several comments that any new calculation methodologies should be applied across all States and be approved at EPA Headquarters, and that all States should use the same methodology.

A few commenters did not agree, however. One said that EPA should not recalculate the budgets upward. Another said there should be no downward ratcheting of budgets. One

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commenter said that it would be premature to assume that as new information becomes available the budget should be adjusted to reflect this. According to this commenter, it would be more appropriate to perform a complete air quality modeling analysis to determine if an adjustment in States' NO_X budgets is in order.

The divergent views reflected in these comments has convinced EPA that it should clarify the role of the budgets in this rule. In light of that role, as explained below, EPA has decided to allow only a limited opportunity to revise the budgets in the very near term. However, under the approach the Agency is following, the rule would not penalize States for not ultimately achieving the budgets, if the State initially projected compliance using the data set forth in this rule, and the State has fully implemented all of the measures reflected in those initial projections, and the measures are as effective in reducing NO_X emissions as they were projected to be in the State plan.

As explained in the NPR, SNPR, and above, EPA based the budgets on its choice of measures that are highly cost-effective and therefore are the easiest for upwind States to implement to reduce transport. However, EPA sought to structure the rule to give the upwind States a choice of which mix of measures to adopt to achieve the aggregate amount of required NO_X emissions reduction.

To offer the States this choice, EPA employed a multi-step approach leading to a numerical budget for each State. In the first step, EPA projected the mass emissions for EGUs and industrial boilers out to 2007, taking into account measures required under the CAA and projected growth. The result was a base case 2007 subinventory for each of those two categories. Next, EPA projected the 2007 mass emissions for other sectors of the emission inventory (e.g., mobile sources), again taking into account projected growth and measures required under the CAA and existing SIPs, thereby creating a base case 2007 subinventory for each of them as well. The aggregation of all of the base case 2007 subinventories is the complete base case 2007 inventory. The EPA then applied cost-effective control measures to the EGU, industrial boiler and other non-EGU source categories as explained in section III., to determine the amount of the reductions from these categories. The EPA applied control measures to the base case inventory to develop the final budget. Thus, the final budget is the sum of (1) the emissions remaining after application of the cost-effective control measures to the subinventories for the categories for which controls are assumed for purposes of budget calculation and (2) the emissions in the base case 2007 subinventories for the categories for which EPA assumed no controls.

The rule then requires each upwind State to use the same base case 2007 inventory in its 1999 SIP submittal as EPA used in developing the State's budget. In that SIP submittal, the State must show that the measures it has adopted will achieve the same aggregate emissions reductions as the control strategies assumed by EPA in developing the State's budget. More specifically, to demonstrate compliance with the SIP call, a State must adopt and implement control measures that are projected to achieve the aggregate emissions reductions determined by EPA based on the application of highly cost-effective controls to EGUs, industrial boilers and other affected non-EGUs. While a State may choose to achieve those reductions through application of measures other than those used by EPA in calculating required reductions, any measures it adopts must achieve the reductions assumed by EPA in the development of its budgets.

The control measures that the State chooses to require will become the enforceable mechanism under the NO_X SIP call. If a State elects to regulate boilers, turbines or combined cycle units that are greater than 250 mmBtu/hr— regardless of whether they are connected to an electrical generator of any size—or to regulate boilers, turbines and combined cycle units that serve electrical generators greater than 25 Mwe, regardless of the heat input capacity of the unit, the State must provide mass emissions limits or their equivalent (see section VI.A.2) for these sources or source categories. The mass emissions limits may be set on a source- by-source basis or may be set for an entire group of sources allowing trading between the sources. These mass emission limits must assume growth no greater than EPA's calculations. Any growth that occurs in that category would have to be accommodated within the mass emission allocations provided by the State for that category, even if the growth in that category should prove to exceed EPA's projections. This is appropriate because as discussed in the SNPR and Section VI.A.2. of today's preamble, EPA believes that the control approaches, growth assumptions, and monitoring for this group of sources have advanced to the point that complying with, tracking, and enforcing a maximum mass emissions limit is reasonable. Furthermore, based on the analyses in the RIA, EPA believes that mass emission limits remain highly cost-effective for these categories when growth is accommodated within the limits. The EPA modeled the expected growth in capacity and capacity utilization of the source categories listed above based on growth assumptions in the IPM that have been subject to extensive public comment and refinement over a several-year period. On the basis of their growth, assumptions and assumed emissions rates, EPA determined that mass emission limits would remain highly cost-effective when new sources are covered within the limits. EPA projects that even if actual growth for this group of sources exceeds the projected growth by over one-third, mass emission limits would remain highly cost-effective according to the criteria used for this rule.

For other categories, EPA will not require a State to remain within a mass emission allocation. Today's rule does require a State to use the base case 2007 inventory in its budget demonstration. However, the rule does not require States to obtain additional reductions in cases where a State's 2007 emissions exceeds its budget due to higher than expected emissions from source categories other than the categories listed above (certain boilers, turbines, and combined cycle units). These exceedances may be the result of growth that exceeds projections for those source categories. However, if a State elects to control these other source categories to achieve the required reductions in whole or part, the adopted measures must be as effective in reducing NO_X emissions as they were projected to be in the State plan. Any failure by a State to adopt measures adequate to achieve reductions equal to the required amount would be treated as noncompliance with this rule. Any failure by the State to implement these measures by the appropriate date would be considered a failure to implement those measures.

In contrast, the overall budget number itself is not enforceable against the State. The budget serves as a tool for projecting in advance whether a State has adopted measures that would produce the required amount of emissions reductions, as indicated by the initial demonstration submitted in September 1999. The budgets are also a means for determining from 2003 to 2007 whether States are fully implementing those measures. Thus, the budgets are an accounting mechanism for ensuring that the upwind States have adopted and implemented control measures that prohibit the significant

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amounts of NO_X emissions targeted by section 110(a)(2)(D)(i)(I).

Given that States will not be subject to enforcement actions if emissions in 2007 from uncontrolled sectors exceed the base case 2007 inventory projections, EPA does not intend to revise those projections merely because such new information becomes available over time. Rather, EPA intends to allow commenters an additional opportunity to request revisions to the source-specific data used to establish each State's budget in this SIP call. This opportunity will be made available during the first sixty days of the 12-month period between signature of today's rule and the deadline for submission of the required SIP revisions (i.e., November 23, 1998). Commenters would need to submit any proposed changes in their inventories to the EPA Air and Radiation docket (A–96–56) within that sixty day period. Individuals interested in modifications requested by commenters may review the materials as they are submitted and available in the docket. At the end of this period, EPA will, within sixty days, evaluate the data submitted by commenters and, if it is determined to be technically justified, revise this rule to incorporate it into the State budget determinations. For a comment to be considered, the request for modification must be submitted in electronic format containing, at a minimum, the data elements listed below for each source category. Additionally, no comment will be considered unless information is provided to corroborate and justify the need for the requested modification. For example, corroborating information in the case of the EGUs can be the inclusion of copies of each source's official same year EIA 860 or 861 form submissions that support the requested change. For non-EGUs, corroborating information can include 1995 operational and emissions information officially submitted (during that time period) by the source to a federal, State, or local government regulating entity.

Each request for modification of data for EGU sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Plant ID numbers (ORIS code preferred, State agency tracking number also or otherwise).
- Unit ID numbers (a unit is a boiler or other combustion device).
- Unit type (also known as prime mover; e.g., wall-fired boiler, stoker boiler, combined cycle, combustion turbine, etc.).
- Primary fuel on a heat input basis.
- Maximum rated heat input capacity of unit.
- For electrical generating units, nameplate capacity of the largest generator the unit serves.
- For 1995 and 1996 ozone season heat inputs.
- 1996 (or most recent) average NO_X rate for the ozone season.
- Latitude and longitude coordinates.
- Stack parameter information (height, diameter, flow, etc.).
- Operating parameters (hours per day, seasonal throughput, etc.).
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for non-EGU point sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Facility primary standard industrial classification code (SIC).
- Plant ID numbers (NEDS, AIRS/AFS, and State agency tracking number also or otherwise).
- Unit ID numbers (a unit is a boiler or other combustion device).
- Primary source classification code (SCC).
- Maximum rated heat input capacity of unit.
- 1995 ozone season or typical ozone season daily NO_X emissions.
- 1995 existing NO_X control efficiency.
- Latitude and longitude coordinates.
- Stack parameter information (height, diameter, flow, etc.).
- Operating parameters (hours per day, seasonal throughput, etc.).
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for stationary area and nonroad mobile sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Primary source classification code (SCC).
- 1995 ozone season or typical ozone season daily NO_X emissions.
- 1995 existing NO_X control efficiency.
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for highway mobile sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Primary source classification code (SCC) or vehicle type.
- 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT).
- 1995 existing NO_X control programs.
- Identification of specific change to the inventory, and
- The reason for the change.

After this initial "shake out" period before submission of the SIP revisions, EPA will not adjust inventories or the resulting State budgets merely because some new information on a segment of EPA's projections comes to its attention. However, when EPA reviews each State's reports, it will pay special attention to the causes for any exceedance of the portions of the inventory that the State is controlling as a means to meet today's rule. If a State exceeds its budget because of greater-than-expected growth in areas not having additional controls, EPA would not penalize the State by requiring the State to offset those increased emissions. Rather, EPA would use the base case projections for all sectors (as revised after the initial period described above) and focus on whether the State had implemented the measures that its 1999 demonstration had shown would, based on those base case inventories, achieve the budget levels. Similarly, the rule would not penalize the State if components in the budget prove inaccurate because of changes in models (e.g., the release of an updated MOBILE model) or because of technical errors (e.g., the size of a unit was incorrectly identified in the inventory, a unit was double-counted, or the RACT level assumed in the base is different from what the State ultimately selected as RACT with EPA approval).

In the NPR, EPA also raised the question of what would happen if EPA adopts national measures beyond what EPA already assumed in the base case 2007 inventory. The EPA indicated that it could use either of two approaches in response: (1) States could receive credits for the real emission reductions that result from the new Federal measures and, therefore, implement a smaller portion of its planned emission reductions, or (2) States would be required to continue to implement the measures in their revised SIPs because affected States are required to continue to achieve emissions reductions equivalent to those which can be achieved through application of highly cost-effective control measures.

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One commenter supported the emission reduction credit for State SIPs resulting from new Federal national measures adopted after the State emission budgets are defined but before 2007. According to this commenter, in such a case the State could implement a smaller portion of its planned emission reductions because of the reduction brought about by the Federal national rule. Another commenter said the EPA should allow full credit for all Federal measures and encouraged the EPA to timely implement and adopt all Federal measures. A State said States should be allowed to take full SIP credit for Federal measures which are implemented in these States. According to one commenter, not allowing States to take credit for new Federal measures would have the effect of downward ratcheting of NO_X budgets. Other States said new Federal measures not accounted for in the SIP call should not be used to offset State measures required to achieve the mandated NO_X emissions reductions.

The EPA has decided to adopt the second approach described above. Thus, EPA's adoption of a national measure not reflected in the base case 2007 inventory would not allow the State to avoid a measure that would otherwise be needed to demonstrate that the State will achieve the required reductions. As stated above, the SIP must prohibit all emissions that contribute significantly to downwind nonattainment and maintenance problems. The State therefore is required to eliminate an amount of emissions corresponding to what is achievable with the highly cost-effective measures identified in this notice. The comments received have not provided an adequate basis for concluding that EPA's adoption of an additional national measure justifies scaling back on that requirement. For that reason, EPA will not allow States to adjust the base case 2007 inventory inventories to reflect any such additional national measures. Rather, for these reports the States should continue to use the base case 2007 inventory set forth in this rule.

In the SNPR, EPA also discussed establishing a process for reassessing the State budgets for the post-2007 timeframe. Today's final rule is based on analyses using the most complete, scientifically-credible tools and data available for the assessment of transport. The EPA expects that there will be a number of updates and refinements in air quality methodologies and emissions estimation techniques over the next 10 years. Therefore, EPA intends to reassess ozone transport using the latest emissions and air quality monitoring data and the next generation of air quality modeling tools. The reassessment will include an evaluation of the effectiveness of the regional NO_X measures States have implemented in response to today's final rule. Modeling analyses will be used to evaluate whether additional local or regional controls are needed to address residual nonattainment in the post-2007 timeframe. The assessment will also examine differences in actual growth versus projected growth in the years up to 2007 as well as expected future growth throughout the entire OTAG region. The reassessment will also review advances in control technologies to determine what reasonable and cost-effective measures are available for purposes of controlling local and regional ozone problems. In addition, EPA will continue to look at the issues that surround the use of output-based State budget allocations. Based on this reassessment, EPA may establish new budget levels and allocation mechanisms for the post-2007 timeframe. The current budget levels and the measures used to comply with today's final rule will remain in effect until EPA takes action on establishing new State budgets.

6. Compliance Supplement Pool

The EPA has received comments expressing concern that some sources may encounter unexpected problems installing controls by the compliance deadline that, in turn, could cause unacceptable risks for a source and its associated industry. More specifically, commenters have expressed concerns related to the electricity industry. If unexpected problems arise for specific sources that are used to generate electricity, some commenters believe that compliance with the May 1, 2003 deadline could adversely impact the reliability of the electricity supply. Commenters that raised concerns regarding the compliance deadline generally supported additional compliance flexibility for the SIP call.

In both the NPR and SNPR, EPA solicited comment on a number of provisions that would provide additional flexibility to both States and sources for the requirements of the NO_X SIP call. In the NPR, EPA proposed that the NO_X SIP call would require full implementation of controls by no later than September 2002, but solicited comment on the range of implementation dates from between September 2002 and September 2004. In addition to the compliance deadline, EPA also solicited comment on the role of banking as a separate compliance flexibility for the NO_X SIP call. Banking may generally be defined as allowing sources that make emissions reductions beyond current requirements to save and use these excess reductions to exceed requirements in a later time period. Depending upon the design of a trading program, banking provisions can provide companies greater latitude for when controls are installed at particular sources. In the SNPR, EPA presented a range of options for incorporating banking in the NO_X Budget Trading Program including early reduction provisions and phasing in controls. The EPA received many comments supporting banking in the NO_X Budget Trading Program and also as a general flexibility mechanism that should be permissible for any State program used to comply with the NO_X SIP call.

In response to comments supporting an extended compliance deadline, EPA has moved the deadline from the proposed date of September 2002 in the NPR to May 1, 2003. As discussed further in Section V, this change provides sources 7–8 additional months for implementing control requirements while ensuring that controls are fully implemented by the 2003 ozone season. The EPA believes that the compliance date of May 1, 2003 for NO_X controls to be installed to comply with the NO_X SIP call is a feasible and reasonable deadline. See Section V.A.1. and the technical support document ''Feasibility of Installing NO_X Control Technologies By May 2003'' for further discussion.

To provide additional flexibility to States and sources for complying with the NO_X SIP call beyond the extension of the compliance deadline, EPA is establishing banking provisions and a compliance supplement pool in today's final rule. The banking provisions are outlined in Section III.F.7. The compliance supplement pool is a voluntary provision that provides flexibility to States in addressing concerns associated with full compliance by May 1, 2003. Each State will be able to use the pool to cover excess emissions of sources that are unable to meet the compliance deadline during the 2003 and 2004 ozone seasons. The pool may be used to credit sources that make early reductions and to directly delay the compliance deadline for specific sources. Credits issued from the compliance supplement pool will not be valid for compliance past the 2004 ozone season. The EPA established the compliance supplement pool by calculating one pool for the entire NO_X SIP call region. The pool was then allocated to the States in proportion to the size of the emissions reduction they are required to achieve under the NO_X SIP call so that each

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State has its own compliance supplement pool. The size of each State's compliance supplement pool and the procedures that will apply to the use of the pool are described below.

a. Size of the Compliance Supplement Pool. The EPA believes it is important for the size of the pool to be capped. Capping the pool makes it possible to estimate the potential impact that the compliance supplement pool may have on NO_X emissions during the 2003 and 2004 ozone seasons. Furthermore, EPA does not anticipate problems for sources in meeting the May 1, 2003 deadline. If there are such cases, they should be relatively few in number. Therefore, the size of the pool only needs to be large enough to cover the limited potential for unexpected compliance delays.

Today's final rule sets the size of the regional compliance supplement pool at 200,000 tons. The EPA believes this is a reasonable size for the pool given the analyses that were used in establishing the State NO_X budgets for today's final rule. As discussed in Section V.A.1., EPA believes the most cost-effective control strategies available to comply with the proposed budgets include post-combustion controls (Selective Catalytic Reduction [SCR] and Selective Non-catalytic Reduction [SNCR]) and combustion controls (e.g., low NO_X burners, overfire air, etc.) on large electric generating units and large non-electric generating units. For the reasons cited in Section V.A.1., EPA estimates that the implementation of SCR controls is potentially more complicated and requires more time than SNCR or combustion controls and, therefore, would determine what the longest schedule would be for full implementation of the assumed NO_X controls. Since EPA estimates that a single SCR installation will take about 23 months, EPA expects the first SCR installations to be completed in 2001. Since compliance is required by 2003, one can assume 33 percent of SCR capacity will be installed each year from 2001 to 2003. The 200,000 ton number is sufficient to cover the excess emissions that must be offset if one year's worth of SCR installations were delayed by a year. Table III–3 shows each State's compliance supplement pool. The 200,000 tons were allocated to States in proportion to the size of the emissions reduction they are required to achieve under the NO_X SIP call. The EPA used this allocation methodology based on the assumption that the need for the pool would be directly related to the magnitude of the emissions reductions required in each State to comply with the NO_X SIP call.

TABLE III–3.—STATE COMPLIANCE SUPPLEMENT POOLS

[Tons]

State	Base	Budget	Tonnage reduction	Compliance supplement pool
Alabama	218,610	158,677	59,933	10,361
Connecticut	43,807	40,573	3,234	559
Delaware	20,936	18,523	2,413	417
District of Columbia	6,603	6,792	(189)	0
Georgia	240,540	177,381	63,159	10,919
Illinois	311,174	210,210	100,964	17,455
Indiana	316,753	202,584	114,169	19,738
Kentucky	230,997	155,698	75,298	13,018
Maryland	92,570	71,388	21,182	3,662
Massachusetts	79,815	78,168	1,648	285
Michigan	301,042	212,199	88,842	15,359
Missouri	175,089	114,532	60,557	10,469
New Jersey	106,995	97,034	9,960	1,722
New York	190,358	179,769	10,590	1,831
North Carolina	213,296	151,847	61,450	10,624
Ohio	372,626	239,898	132,728	22,947
Pennsylvania	331,785	252,447	79,338	13,716
Rhode Island	8,295	8,313	(18)	0
South Carolina	138,706	109,425	29,281	5,062
Tennessee	252,426	182,476	69,950	12,093
Virginia	191,050	155,718	35,332	6,108
West Virginia	190,887	92,920	97,967	16,937
Wisconsin	145,391	106,540	38,851	6,717
Total	4,179,751	3,023,113	....	200,000

b. State Distribution of the Compliance Supplement Pool. States have two options for making the pool available to sources. One option is to distribute some or all of the pool to sources that generate early reductions during ozone seasons prior to May 1, 2003. The second option is to run a public process to provide tons to sources that demonstrate a need for a compliance extension. A State wishing to use the compliance supplement pool may divide the State pool and make some of it available to sources through both options, or may use only one of the options for distributing the pool to sources prior to May 1, 2003 according to the procedures discussed below. Tons that are not distributed by a State prior to May 1, 2003 will be retired by EPA.

(1) Early Reduction Credits. The EPA encourages States to consider making the compliance supplement pool available to sources through an early reduction credit program. States may use early reduction credits as an incentive for sources to make NO_X emissions reductions prior to the 2003 ozone season that would otherwise not occur. By generating early credits or acquiring them from other sources, companies will be able to use the early reduction credits to extend the timeframe for achieving actual emissions reductions at specific sources that may require additional time. To establish an early credit program, States that participate in the NO_X Budget Trading Program may use the provisions

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set forth in that trading program (See Section VII.F). States not participating in the NO_X Budget Trading Program are also free to develop their own rules for granting early reduction credits and recognizing the credits for compliance during the 2003 and 2004 ozone seasons. The procedures for establishing an early credit program are presented below in Section III.F.7.c.

(2) Direct Distribution to Sources. States may also distribute the compliance supplement pool directly to sources that demonstrate a need for the compliance supplement. Under this approach, sources would be responsible for demonstrating to the State and public that achieving compliance by May 1, 2003 would create undue risk either to its own operation or its associated industry. Before granting a direct distribution to a source, the State must provide the public an opportunity to comment on the validity of the need for direct distribution of the compliance supplement. The direct distribution process must be initiated and completed between September 30, 2002 and May 1, 2003. States which choose to grant early reduction credits cannot conduct the direct distribution until all early reduction credits have been issued by the State. By postponing the direct distribution until after September 2002, sources will have the maximum opportunity to achieve compliance, either through installation of controls or with early reduction credits, before using this option. States and the public will also be better positioned to determine legitimate requests after September 2002.

To ensure that direct distribution of the compliance supplement is only provided to sources that truly need a compliance extension, States are only permitted to give credits to an owner or operator of a source that demonstrates the following:

- The process of achieving compliance by May 1, 2003 would create undue risk for the source or its associated industry. For electric generating units, the demonstration should show that installing controls would create unacceptable risks for the reliability of the electricity supply during the time of installation. This demonstration would include a showing that it was not feasible to import electricity from other systems during the time of installation. Non-electric generating sources may also be eligible for the compliance supplement based on a demonstration of risk comparable to that described for the electricity industry.
- For a source subject to an early reduction credit program, it was not possible to compensate for delayed compliance by generating early reduction credits at the source or by acquiring credits generated by other sources.
- For a source subject to an emissions trading program, it was not possible to acquire allowances or credits for the 2003 ozone season from sources that will make reductions beyond required levels during the 2003 ozone season.

7. Banking

As noted in the NPR and SNPR, States have the flexibility to choose their own set of control measures to meet their Statewide NO_X budget established under the NO_X SIP call. States and sources have supported the use of emissions trading programs as a control measure for complying with the NO_X SIP call requirements. EPA has provided a model cap-and-trade program (NO_X Budget Trading Program) for large stationary sources that States can adopt as one option for establishing an emissions trading program. A number of commenters (both States and sources) have also expressed interest in pursuing alternative trading programs in addition to or as a substitute for the NO_X Budget Trading Program. One possible flexibility mechanism available to sources subject to an emissions trading program is the ability to bank emissions reductions. Banking may generally be defined as allowing sources that make emissions reductions beyond required levels to save and use these excess reductions to compensate for emitting emissions above required levels in a later time period. In the SNPR, EPA requested comment on whether and how banking should be incorporated into the design of the NO_X Budget Trading Program. In the proposal, four banking options were presented: (1) Banking would not be a feature; (2) banking would begin when the trading program begins (May 2003); (3) sources would be allowed to generate early reductions credits for use after the start of the program and banking would continue after the program begins; (4) banking would begin with the first phase of a two-phase trading program and continue thereafter (i.e., phased-in control requirements). The EPA also requested comment on options for managing the use of banked allowances in order to limit the potential for emissions to be significantly higher than budgeted levels because of banking. The EPA specifically proposed using a ''flow control'' mechanism in the latter two banking options where the potential exists for a large amount of banked allowances to be available for use at the start of the program.

a. Banking Starting in 2003. Comments for the NO_X Budget Trading Program were generally supportive of including banking in the trading program. Commenters noted that allowing sources to make excess reductions in one year and use these reductions to emit above required levels in a later year encourages early and cost- saving emission reductions, helps avoid end-of-season emissions spikes (because unused allowances retain their value for compliance in future years), and encourages more expedient development and implementation of NO_X control technology. Commenters pointed out that banking also provides sources flexibility in achieving emission reduction goals, allowing them to save allowances in years when the cost of achieving a given emission level is relatively low for use in years when the cost is relatively higher (for example, a year characterized by low availability of nuclear and hydro generation capacity would be a higher cost year). Thus, banking was seen by many commenters as a critical tool for sources to respond to uncertainty. Some commenters, however, expressed caveats along with their support for banking. They cited the need for some form of bank management to ensure that the use of banked allowances does not detract from the environmental goal of the NO_X SIP call. At least one commenter recommended that EPA identify banking as an area to be reviewed for problems during audits of the program to ensure it did not have a detrimental impact.

The EPA also received comments supporting banking that were not specific to the NO_X Budget Trading Program. Many commenters addressed the concept of banking when proposing alternative strategies for establishing and implementing the State budgets that were proposed in the NO_X SIP call. These comments regarded banking as a fundamental factor in establishing the timing and control level for the State budgets. With all other factors being equal, a NO_X SIP call that allows banking provides additional flexibility and cost savings to affected sources than a NO_X SIP call without banking. For this reason, many commenters included banking in their alternative proposals.

In order to provide additional flexibility to States and sources under the NO_X SIP call as discussed in section III.F.6., and recognizing that States may pursue alternative trading programs other than the NO_X Budget Trading Program, the Agency believes it is important to establish criteria for banking that would apply to all programs that States may use to comply with requirements of the NO_X SIP call.

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Therefore, EPA is setting forth provisions in today's final rule that will allow banking in the NO_X Budget Trading Program and other State trading programs. Trading programs used to comply with the NO_X SIP call may allow banking to start in the first control period of the program, May 1 through September 30, 2003. Beginning in that control period, States may allow sources included in these programs to bank NO_X emissions reductions not otherwise required by the State's SIP, for compliance in future control periods. As outlined below, the banking provisions also require the use of a flow control mechanism beginning in 2004 and allow States to credit early reductions generated by sources prior to 2003 that may be used for compliance only in the 2003 and 2004 ozone seasons. The final rule for the NO_X Budget Trading Program conforms with these banking provisions. Additionally, alternative emissions trading programs used to comply with the SIP call will be subject to these banking criteria as well other applicable criteria in § 51.121 and any other applicable EPA guidance such as the Economic Incentive Program rules and guidance.

b. Management of Banked Allowances. Many utility and industry commenters generally opposed the use of discounts or constraints on banked allowances, arguing that such measures would reduce the incentives to control emissions beyond required levels. In addition, commenters felt the measures were overly complex and restrictive, as well as unnecessary, since the stringent control level proposed would serve as a barrier to overcontrol, precluding the establishment of a sizeable bank. Several commenters remarked that any decision regarding whether and to what extent a trading program should impose restrictions on the use of banked allowances should proceed from an analysis of the air quality effects of that use; in the absence of such an analysis, there would be little basis for imposing restrictions or for deciding what restrictions would properly address air quality effects. However, these commenters did not provide analyses demonstrating that the use of banked allowances in any given season would not be a problem in the context of the NO_X SIP call. One commenter pointed out specifically that the sheer magnitude of the SIP call region should preclude EPA from implementing a flow control management scheme similar to that used under the Ozone Transport Commission's (OTC) trading program, since protection of problem areas would not be feasible on such a large scale.

Several commenters who were opposed to the management of banked allowances, however, stated that if restrictions were to be imposed, they would favor flow control as the most cost-effective, least rigid means of management. A few commenters added that, if implemented, flow control should be applied on a source-by-source basis so as to avoid penalizing all of the participants in the trading program for the excess banking of individual participants. One commenter stated that if EPA concludes that there is an adequate basis for imposing some type of restriction, it should avoid placing any absolute limit on the amount of banked allowances that can be used in a given season. Another commenter suggested that if EPA chooses to propose managed banking, it should consider establishing an initial period without managed banking upon which a managed banking program can later be based if it turns out that ''trading contributes to nonattainment.'' Several additional commenters, most notably northeastern States and a few environmental groups, supported the use of a flow control management system to discourage excess use of banked allowances in any one ozone season. One such commenter suggested that EPA conduct an analysis similar to that used by the OTC in determining the appropriate level of flow control for the SIP call region.

Based on the stated goal of the NO_X SIP call, to achieve specified limits on NO_X emissions for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States, EPA believes it is appropriate to place some limitation on the amount of emissions variability that may occur with banking, and therefore, occur with the transport of NO_X. At the same time, any limitations on banking should still fit within the market-based structure of trading programs, rather than imposing overly stringent limits that would potentially eliminate the advantages of having banking in the first place. For these reasons, EPA is including a provision in today's final rule requiring any State program used to comply with the requirements of the NO_X SIP call that allows banking to limit the potential effects of banking through a flow control mechanism as described below. The flow control mechanism will be applicable starting in the 2004 ozone season. In this year, unused credits from the compliance supplement pool as well as unused credits or allowances from the 2003 ozone season would be considered banked.

The EPA believes that the flow control mechanism serves as an important insurance policy against emissions variability in emissions trading programs used to comply with the NO_X SIP call. The mechanism as described below would only restrict the use of banked allowances or credits when a significant amount are used for compliance in a specific ozone season. Based on the analyses in the RIA, EPA believes that the flow control mechanism is set at a level that will allow sources to use banking without restriction. However, the flow control mechanism provides the extra security to downwind areas that banking will not result in significant increases of emissions above budgeted levels. The EPA also recognizes that a wide variety of emissions trading programs may be used by States. Therefore, the requirements for the flow control mechanism described below are intended to be general, thus allowing States the flexibility to adjust the flow control mechanism to fit the specific needs of each program. Section VII.F. also provides further discussion of the flow control mechanism and describes how it is incorporated into the NO_X Budget Trading Program.

The flow control mechanism allows the unlimited banking of emissions reductions by sources during and after 2003, but discourages the ''excessive use'' of banked allowances or credits by establishing either an absolute limit on the number of banked allowances or credits that can be used each season or a rate discounting the use of banked allowances or credits over a given level. The key issue with flow control is to establish the level at which flow control is triggered. In the SNPR, EPA solicited comment on establishing the level at 10 percent of the ozone season budget for the sources included in the trading program. This level was proposed because 10 percent seems to be a reasonable number that would allow a significant amount of banked allowances or credits to be used, but not so many as to jeopardize the intended effects of the NO_X SIP call in a given season. The EPA also proposed the 10 percent number because it is the level used for flow control in the OTC's trading program. Although some commenters questioned whether this number is appropriate for the NO_X SIP call region, commenters did not provide explicit analyses or recommendations for a different number. Thus, EPA continues to believe that 10 percent is a reasonable number and is including this in today's final rule. Based on the analyses in the RIA, EPA does not

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anticipate sources to bank above the 10 percent level. Therefore, this level should prevent significant emissions increases resulting from banking without restricting sources normal operations. The effect of flow control set at 10 percent of the trading program budget is that for a given season, sources may use banked allowances or credits for compliance without restrictions in an amount up to 10 percent of the NO_X budget for those sources in the trading program. Banked allowances or credits that are used in an amount greater than 10 percent of the NO_X budget for those sources will have restrictions that are described below.

The EPA believes it is necessary to provide flexibility to States for determining how to apply the 10 percent flow control in individual trading programs and for determining the appropriate restrictions for banked allowances or credits that are used in an amount greater than the 10 percent number. States have the flexibility to apply the flow control mechanism to specifically control the use of banked allowances or credits at each source or to apply the mechanism more broadly across the entire trading program. For example, by applying flow control at the source level, a State would allow each source participating in the trading program to use banked allowances without restrictions in an amount not greater than 10 percent of its allowable NO_X emissions for the ozone season. Conversely, flow control could be applied so that individual sources may use banked allowances or credits in an amount more than 10 percent without restrictions, but the total number used throughout the entire trading program (i.e., total number of banked credits or allowances used for compliance throughout all States participating in the trading program) could not exceed 10 percent of the allowable NO_X emissions for all sources in the trading program without restrictions. The net effect is the same under either approach—banked allowances or credits may be used each year without restrictions in an amount that does not exceed 10 percent of the allowable NO_X emissions for all sources covered by the trading program. The NO_X Budget Trading Program uses the latter approach. See Section VII.F. for more details.

The second issue for the flow control mechanism is to determine what restrictions should be placed on banked allowances or credits that are used in an amount greater than 10 percent of the allowable NO_X emissions for all sources covered by the trading program. Again, EPA is providing flexibility for the restrictions that States may use. States may use a discount that is no less than two-for-one, requiring sources to retire one additional banked allowance or credit for each banked allowance or credit used for compliance in an amount greater than the 10 percent level. Or States may set the 10 percent level as a hard cap and not allow any banked allowances or credits to be used in an amount greater than the 10 percent level. Although the discount option provides more flexibility to sources and more uncertainty regarding NO_X emissions in a given year, EPA believes both options serve as an acceptable restriction for limiting the variability of emissions associated with banking. As described in Section VII.F, the NO_X Budget Trading Program uses the 2-for-1 discount as the applicable restriction.

c. Early Reduction Credits. The majority of commenters for the NO_X Budget Trading Program generally supported the option of awarding early reduction credits. Commenters noted that the issuance of credits will provide cost savings and environmental benefits by encouraging early reductions, facilitate compliance with the budget by allowing sources to earn allowances that may be used to delay more stringent emission reductions, and stimulate the market by ensuring allowances are available for trading at the program start. Several commenters advocated making early reduction credits available for any reductions that exceed baseline controls, whereas other commenters supported early reduction credits only if they exceed the controls required under the SIP call, as was proposed by EPA. A few other commenters suggested levels between these two options. A few OTC States suggested that OTC allowances banked in Phase II (between 1999–2003 for reductions beyond an approximate 0.20 lb/mmBtu rate) could be used as early reduction credits in the NO_X Budget Trading Program, either one-for-one or at a discount ratio, depending on the level beyond which credits were awarded in the latter program. A few remaining commenters, concerned about the potential for creating or exacerbating ozone violations, supported early reduction credits and banking only if coupled with flow control.

Regarding the appropriate length of the period in which early reductions could be earned, some commenters supported EPA's proposed option in the SNPR of a two-year early reduction period, while others favored a three or four-year period. At least one commenter specifically recommended that the early reduction period start in January 1995, while another suggested September 1998. Several commenters rejected EPA's suggestion that early reduction credits be calculated as a set-aside from the first five years of allowances, arguing that treating the credits as set-asides would be inconsistent with the nature of early reduction credits. Conversely, a few other commenters felt the credits should be awarded from within State budgets to avoid budget inflation. Additional commenters criticized EPA's suggestion that if early reduction credits were awarded, they be awarded at the company level, arguing instead for individual source awards. One commenter stated that awards on a company basis would not address the load shifting concerns EPA cited, while another thought EPA could address the load shifting concern by basing credits on activity levels in a historic period rather than by shifting to a company-level award. Finally, at least one commenter felt that States should be able to independently establish parameters for awarding voluntary early reductions.

For the reasons set forth in Section III.F.7, Compliance Supplement Pool, EPA is allowing, but not requiring, States to grant early reduction credit to sources that reduce their ozone season NO_X emissions below levels specified by the State prior to the 2003 control period. The early reduction credits may be used by sources for compliance during the 2003 and 2004 ozone seasons. EPA believes that an early credit program can be helpful to encourage emissions reductions prior to the 2003 ozone season that would not be made without an economic incentive for the sources to act. Furthermore, the early credit program will provide additional allowances or credits for use during the 2003 and 2004 ozone seasons. By generating early credits or acquiring early credits from other sources that generated credits, companies would have greater latitude in determining when actual emissions reductions are achieved at specific sources. As discussed in Section III.F.7, this may be beneficial to some companies that are concerned about the time and effort required to install all necessary emissions controls prior to May 2003. States will be limited in the amount of early reduction credits that they may grant by the amounts set forth in Section III.F.7 Compliance Supplement Pool. The potential pool of credits that is available to each State is intended to be large enough to provide a real incentive for early reductions and enough flexibility to allow the installation of some control equipment, if necessary, past May 2003.

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Section VII.F. of today's preamble outlines how the early credit program is being incorporated into the NO_X Budget Trading Program and how banked allowances from the OTC program may be integrated with this provision. States that develop alternative trading programs may craft their early reduction program to meet the needs of their specific trading program. The following outlines the general requirements that any early reduction program used to comply with the NO_X SIP call should meet. For an emission reduction to be eligible as an early reduction credit, it must meet the following criteria:

- Surplus—The reduction is not contained in the State's SIP or otherwise required by the CAA.
- Verifiable—The reduction can be verified as actually having occured.
- Quantifiable—The reduction is quantified according to procedures set forth by the State and approved by EPA.

Early reduction credits generated by sources serving electric generators with a nameplate capacity greater than 25 MWe or greater or boilers, combustion turbines and combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, should be quantified according to the monitoring provisions of part 75, subpart H as required in § 51.121(h)(1)(iv).

Beyond the above requirements, States are free to develop an early credit program that meets the needs of their specific trading program provided the State does not issue credits in an amount greater the size of the credit pool presented in Section III.F.7. A State's early credit program may be established for any ozone season occurring after a State's early credit rule is approved by EPA into the State's SIP revision and before May 1, 2003.

To ensure that a State does not issue an amount of early credits beyond the amount specified in each State's compliance supplement pool, EPA recommends that a State develop procedures to be used in case there is an over-subscription of the early credit pool. Possible options include granting early credits on a first-come, first-served basis or waiting until all applications are submitted and then discounting the early credits on a pro-rata basis so that the amount of early credits issued equals the size of the State's pool. States may also influence the amount of early credits that sources generate by considering what level of emissions reductions the State will recognize as early reductions. For example, a State may choose to issue early reduction credits for any reductions below applicable requirements. However, the State may choose to make the demonstration more stringent by requiring early reduction credits to be generated by reductions that are below a limit that is tighter than applicable requirements (e.g., grant early reductions that are 30 percent below applicable requirements or below a fixed level such as 0.20 lb/mmBtu).

In the SNPR, EPA also solicited comment on a phased-in NO_X Budget Trading Program that would begin in 2001, two years prior to the compliance date for the NO_X SIP call. In response to the proposal, most commenters that discussed the phase-in program option were generally opposed to it. Their primary argument was that such a program would effectively accelerate the compliance date for NO_X controls under the SIP call. A few commenters, however, still supported the phase-in approach as a means of mitigating the uncertainties inherent in the allowance market that would develop for the 2003 control period, allowing sources to gain experience prior to 2003. Some commenters specifically favored a phase-in approach only if it does not interfere with the 2003 ozone season compliance schedule, whereas others supported a phase-in approach as a means of reducing the burdens of the 2003 ozone season compliance schedule.

Today's final rule requires States to achieve the necessary emissions reductions by May 2003 and does not require States to phase-in controls prior to 2003. States that wish to phase-in controls prior to 2003 as a part of a State trading program may do this, but they are not required to do so to comply with the NO_X SIP call. States that establish a phased-in trading program in order to allow sources to generate early reduction credits will be subject to the requirements for early reductions as described above, including the requirement that a State may not grant an amount of early reductions in excess of the State's compliance supplement pool. For a discussion of how the Ozone Transport Commission's trading program may be integrated with the compliance supplement pool and the early reduction provisions, see Section VII.F, which describes the banking provisions of the NO_X Budget Trading Program.

G. Final Statewide Budgets

1. EGU

a. Description of Selected Approach. As described in Section III.B.3. of this notice, the EGU budget component is calculated based on applying a 0.15 lb/mmBtu emission limit to sources greater than 25 MWe. This limit is applied uniformly across all States that are covered by this SIP call. The higher of 1995 or 1996 heat input, grown to 2007 is used to calculate the budget component.

b. Summary of Budget Component. Both the 2007 electricity generating Base Case and the electricity generating Budget component were revised from the levels in the SNPR based on the changes described in Section III.B.3. of this notice. These revisions are shown in Tables III–4 and III–5. The difference between the revised 2007 Base Case and Budget emissions from the SNPR and the final Base Case and Budget emissions is shown in Table III–4. Negative changes indicate decreases. The final percent reduction from the 2007 Base Case to the Budget is shown in Table III–5.

TABLE III–4.—CHANGES TO REVISED SNPR BASE CASE AND BUDGET COMPONENTS FOR ELECTRICITY GENERATING UNITS

[Tons NO_X/season]

State	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Alabama	85,201	76,900	–10	30,644	29,051	–5
Connecticut	7,048	5,600	–21	5,245	2,583	–51
Delaware	10,727	5,800	–46	4,994	3,523	–29
District of Columbia	236	*0	–100	152	207	36
Georgia	84,890	86,500	2	32,433	30,255	–7
Illinois	119,756	119,300	0	36,570	32,045	–12
Indiana	159,917	136,800	–14	51,818	49,020	–5
Kentucky	130,919	107,800	–18	38,775	36,753	–5

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TABLE III–4.—CHANGES TO REVISED SNPR BASE CASE AND BUDGET COMPONENTS FOR ELECTRICITY GENERATING UNITS—Continued

[Tons NO_X/season]

State	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Maryland	37,575	32,600	–13	12,971	14,807	14
Massachusetts	24,998	16,500	–34	14,651	15,033	3
Michigan	73,585	86,600	18	29,458	28,165	–4
Missouri	81,799	82,100	0	26,450	23,923	–10
New Jersey	17,484	18,400	5	8,191	10,863	33
New York	43,705	39,200	–10	31,222	30,273	–3
North Carolina	86,872	84,800	–2	32,691	31,394	–4
Ohio	167,601	163,100	–3	51,493	48,468	–6
Pennsylvania	120,979	123,100	2	45,971	52,000	13
Rhode Island	1,351	1,100	–19	1,609	1,118	–31
South Carolina	57,146	36,300	–36	19,842	16,290	–18
Tennessee	83,844	70,900	–15	26,225	25,386	–3
Virginia	51,113	40,900	–20	20,990	18,258	–13
West Virginia	76,374	115,500	51	24,045	26,439	10
Wisconsin	45,538	52,000	14	17,345	17,972	4
Total	1,568,655	1,501,800	–4	563,784	543,825	–4

*The base case for DC is actually projected to be 3 tons per season. The base case values in this table are rounded to the nearest 100 tons.

TABLE III–5.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR ELECTRICITY GENERATING UNITS

[tons/season]

State	Final base	Final budget	Percent reduction
Alabama	76,900	29,051	62
Connecticut	5,600	2,583	54
Delaware	5,800	3,523	39
District of Columbia	*0	207	NA
Georgia	86,500	30,255	65
Illinois	119,300	32,045	73
Indiana	136,800	49,020	64
Kentucky	107,800	36,753	66
Maryland	32,600	14,807	55
Massachusetts	16,500	15,033	9
Michigan	86,600	28,165	67
Missouri	82,100	23,923	71
New Jersey	18,400	10,863	41
New York	39,200	30,273	23
North Carolina	84,800	31,394	63
Ohio	163,100	48,468	70
Pennsylvania	123,100	52,000	58
Rhode Island	1,100	1,118	–2
South Carolina	36,300	16,290	55
Tennessee	70,900	25,386	64
Virginia	40,900	18,258	55
West Virginia	115,500	26,439	77
Wisconsin	52,000	17,972	65
Total	1,501,800	543,825	64

*The base case for DC is actually projected to be 3 tons per season. The base case values in this table are rounded to the nearest 100 tons.

2. Non-EGU Point Sources

As indicated in the proposal and discussed earlier in this notice, EPA continues to believe that technically feasible control measures costing between an average of $1,000 to $2,000 per ozone season ton (1990 dollars) are highly cost-effective and therefore should be the basis for determining the significant amounts that must be eliminated by each covered jurisdiction. In the SNPR, EPA committed to examining alternatives that would limit the number of affected non-EGU sources for the purpose of establishing emissions budgets, yet still achieve the environmental objective of mitigating broad-scale ozone transport. The EPA examined alternatives that target reductions from the largest non-EGU source category groupings, and within each of the largest groupings applied the cost-effectiveness criteria. The resulting emissions budget covers the majority of emissions from large non-utility sources, and does not include reductions from small sources and sources that, as a group, are not efficient to control, or are already covered by other Federal measures (e.g., CAA § 112 MACT). The description below summarizes the budget approach for non-EGU point sources.

a. Description of Selected Approach.

(1) NO_X Budget Sources. The following approach is used to determine if a unit's emissions would be decreased as part of the budget calculation.

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Industrial boilers, turbines, stationary internal combustion engines and cement manufacturing are the only non-EGU sources for which reductions are assumed in the budget calculation.

1. Use heat input capacity data for each source if the data are in the updated inventory.

2. If heat input capacity data are not available, use the default identification of small and large sources developed by EPA/Pechan for OTAG and also used to develop the NPR and SNPR budgets for source categories with heat input capacity fields (''default data'').

3. Emission reductions would be assumed if specific source heat input capacity data or default data indicate that a source is greater than 250 mmBtu/ hr in the updated inventory.

4. If specific or default heat input capacity data are not available in the updated inventory (or not appropriate for a particular source category), emission reductions would be assumed if the unit's average summer day emissions are greater than one ton per day based on the updated inventory.

5. All others are ''small'' and no emission reductions are assumed.

It should be noted (as described earlier in this section) that no emissions reductions are assumed for point sources with capacities less than or equal to 250 mmBtu/hr but with emissions greater than 1 ton/day for purposes of calculating the budget. This is a change from the NPR which assumed RACT controls on units with capacities less than or equal to 250 mmBtu/hr and emissions greater than 1 ton/day.

(2) Control Levels. For purposes of calculating the State NO_X budgets for the relevant sources (described above), the following emissions decreases from uncontrolled levels were assumed:

1. Non-EGU boilers and turbines—60 % decrease.

2. Stationary internal combustion engines—90 % decrease.

3. Cement manufacturing plants—30 % decrease.

These controls result in an overall reduction in emissions from all affected large non-EGU point sources of almost 40 percent (187,800 tons per season decrease).

Each State's budget is based on application of these controls beginning on May 1, 2003. The EPA recognizes that if States include these source categories in a regionwide trading program, as EPA encourages States to do, each State will comply with its budget through compliance of its sources with the requirements of the regionwide trading program. Of course, under the trading program, sources in a State may acquire or sell allowances that will, in turn, allow for higher or lower emissions levels for that State than assumed in this action. Because EPA has determined that the ambient effect of such a trading program across the region is consistent with the basis for including States in the SIP call (see discussion below at Section IV), EPA has structured its rule to allow a State to meet its budget by including the amount of emissions for which sources in the State hold allowances from out- of-State sources. Overall, total NO_X emissions in the region will be within the budget.

b. Summary of Budget Component. Both the 2007 Base Case and Budget component for non-electricity generating point sources were revised based on the changes described above. Changes to the 2007 base reflect changes in the base year (1995) emissions and changes in growth factors. Changes to the budget components reflect these changes as well as the change in level of control. These resulting budget components are shown in Tables III–5 and III–6. The difference between the 2007 Base Case and Budget emissions as revised in the SNPR and the final Base Case and Budget emissions for non-electricity generating point sources is shown in Table III–6. Negative changes indicate decreases. The final percent reduction from the 2007 Base Case to the Budget is shown in Table III–7.

TABLE III–6.—CHANGES TO REVISED BASE CASE AND BUDGET COMPONENTS FOR NON-ELECTRICITY GENERATING POINT SOURCES

[Tons NO_X/season]

	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Alabama	48,187	49,781	3	24,416	37,696	54
Connecticut	5,254	5,273	0	3,103	5,056	3
Delaware	5,276	1,781	¥66	2,271	1,645	¥28
District of Columbia	311	310	0	259	292	13
Georgia	33,939	33,939	0	14,305	27,026	89
Illinois	65,351	55,721	¥15	40,719	42,011	3
Indiana	51,839	71,270	37	29,187	44,881	54
Kentucky	19,019	18,956	0	11,996	14,705	23
Maryland	10,710	10,982	3	5,852	7,593	30
Massachusetts	9,978	9,943	0	6,207	9,763	57
Michigan	61,656	79,034	28	35,957	48,627	35
Missouri	12,320	13,433	9	9,012	11,054	23
New Jersey	22,228	22,228	0	12,786	19,804	55
New York	20,853	25,791	24	14,644	24,128	65
North Carolina	34,412	34,027	¥1	19,267	25,984	35
Ohio	53,329	53,241	0	30,923	35,145	14
Pennsylvania	74,839	73,748	¥1	41,824	65,510	57
Rhode Island	327	327	0	327	327	0
South Carolina	34,994	34,740	¥1	18,671	25,469	36
Tennessee	67,774	60,004	¥11	34,308	35,568	4
Virginia	25,509	39,765	56	10,919	27,076	148
West Virginia	42,733	40,192	¥6	21,066	31,286	49
Wisconsin	21,263	22,796	7	11,401	17,973	58
Total	722,101	757,281	5	399,416	558,618	40

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TABLE III–7.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR NON-ELECTRICITY GENERATING POINT SOURCES

[Tons/season]

	Final base	Final budget	Percent reduction
Alabama	49,781	37,696	24
Connecticut	5,273	5,056	4
Delaware	1,781	1,645	8
District of Columbia	310	292	6
Georgia	33,939	27,026	20
Illinois	55,721	42,011	25
Indiana	71,270	44,881	37
Kentucky	18,956	14,705	22
Maryland	10,982	7,593	31
Massachusetts	9,943	9,763	2
Michigan	79,034	48,627	38
Missouri	13,433	11,054	18
New Jersey	22,228	19,804	11
New York	25,791	24,128	6
North Carolina	34,027	25,984	24
Ohio	53,241	35,145	34
Pennsylvania	73,748	65,510	11
Rhode Island	327	327	0
South Carolina	34,740	25,469	27
Tennessee	60,004	35,568	41
Virginia	39,765	27,076	32
West Virginia	40,192	31,286	22
Wisconsin	22,796	17,973	21
Total	757,281	558,618	26

3. Mobile and Area Sources

a. Description of Selected Budget Approach. As discussed in Section III.D.3 of the notice, EPA proposed highway budget components based on projected highway vehicle emissions in 2007 from a base year of 1990, assuming implementation of those measures incorporated in existing SIPs, such as inspection and maintenance programs and reformulated fuels, measures already implemented federally, and those additional measures expected to be implemented federally by 2007. As discussed in Section III.E of this notice, EPA proposed nonroad mobile source budget components based on projected nonroad mobile source emissions in 2007 from a base year of 1990. These projections were developed by estimating the emissions expected in 2007 from all nonroad engines, assuming implementation of those measures incorporated in existing SIPs, measures already implemented federally, and those additional measures expected to be implemented federally. For area sources, no cost-effective control measures were identified in the NPR. Because no comments were received that demonstrate that additional controls for highway, nonroad, or area sources are both feasible and highly cost-effective, the final budgets are based on the same levels of controls that were proposed.

b. Summary of Budget Component. Changes were made to the baseline stationary area, nonroad and highway mobile source budget data as discussed in Sections III.D. and III.E. of this notice. Budget components were calculated using the updated baseline and the controls discussed above. The resulting final budget components for these sectors are contained in Tables III–7, III–8, and III–9 below, along with the difference between the proposed Budget emissions and the final Budget emissions. The budget components are not compared to the 2007 base because no reductions were calculated beyond the base case. In the NPR and SNPR, EPA used a 2007 CAA baseline for these source sectors. Because the measures that are assumed in the budgets for these sectors are measures that would occur in the absence of the SIP call, EPA believes that it is more appropriate to use the budget level for these source sectors as the baseline and compare the total budgets to this revised baseline.

TABLE III–8.—FINAL NO_X BUDGET COMPONENTS FOR STATIONARY AREA SOURCES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	25,229	25,225	0
Connecticut	4,587	4,588	0
Delaware	1,035	963	¥7
District of Columbia	741	741	0
Georgia	11,901	11,902	0
Illinois	7,270	7,822	8
Indiana	25,545	25,544	0
Kentucky	38,801	38,773	0
Maryland	8,123	4,105	¥49
Massachusetts	10,297	10,090	¥2

TABLE III–8.—FINAL NO_X BUDGET COMPONENTS FOR STATIONARY AREA SOURCES—Continued

[Tons/season]

	Proposed budget	Final budget	Percent change
Michigan	28,126	28,128	0
Missouri	6,626	6,603	0
New Jersey	11,388	11,098	¥3
New York	15,585	15,587	0
North Carolina	9,193	10,651	16
Ohio	19,446	19,425	0
Pennsylvania	17,103	17,103	0
Rhode Island	420	420	0
South Carolina	8,420	8,359	¥1
Tennessee	11,991	11,990	0
Virginia	25,261	18,622	¥26
West Virginia	4,901	4,790	¥2
Wisconsin	10,361	8,160	¥21
Total	302,350	290,689	¥4

TABLE III–9.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR NONROAD SOURCES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	18,727	16,594	¥11
Connecticut	9,581	9,584	0
Delaware	4,262	4,261	0
District of Columbia	3,582	3,470	¥3
Georgia	22,714	21,588	¥5
Illinois	56,429	47,035	¥17
Indiana	27,112	22,445	¥17
Kentucky	22,530	19,627	¥13
Maryland	18,062	17,249	¥4
Massachusetts	19,305	18,911	¥2
Michigan	24,245	23,495	¥3
Missouri	19,102	17,723	¥7
New Jersey	21,723	21,163	¥3
New York	30,018	29,260	¥3
North Carolina	18,898	17,799	¥6
Ohio	42,032	37,781	¥10
Pennsylvania	29,176	25,554	¥12
Rhode Island	2,074	2,073	0
South Carolina	12,831	11,903	¥7
Tennessee	47,065	44,567	¥5
Virginia	25,357	21,551	¥15
West Virginia	10,048	10,220	2
Wisconsin	15,145	12,965	¥14
Total	500,018	456,818	¥9

TABLE III–10. FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR HIGHWAY VEHICLES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	56,601	50,111	¥11
Connecticut	17,392	18,762	8
Delaware	8,449	8,131	¥4
District of Columbia	2,267	2,082	¥8
Georgia	77,660	86,611	12
Illinois	77,690	81,297	5
Indiana	66,684	60,694	¥9
Kentucky	46,258	45,841	¥1
Maryland	28,620	27,634	¥3
Massachusetts	23,116	24,371	5
Michigan	81,453	83,784	3
Missouri	55,056	55,230	0
New Jersey	39,376	34,106	¥13
New York	94,068	80,521	¥14

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TABLE III–10. FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR HIGHWAY VEHICLES—Continued

[Tons/season]

	Proposed budget	Final budget	Percent change
North Carolina	73,056	66,019	¥10
Ohio	92,549	99,079	7
Pennsylvania	73,176	92,280	26
Rhode Island	5,701	4,375	¥23
South Carolina	49,503	47,404	¥4
Tennessee	67,662	64,965	¥4
Virginia	79,848	70,212	¥12
West Virginia	21,641	20,185	¥7
Wisconsin	41,651	49,470	19
Total	1,179,477	1,173,163	¥1

4. Potential Alternatives to Meeting the Budget

The EPA believes that there are additional control measures and alternative mixes of controls that a State could choose to implement by May 1, 2003. Examples of such measures are described below and illustrate that options are potentially available in several source categories.

The EPA believes that, with respect to EGUs, there is a large potential for energy efficiency and renewables in the NO_X SIP call region that reduce demand and provide for more environmentally-friendly energy resources. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_X emissions proportionately, while the associated generator would produce the same amount of electricity. Renewable energy source generation includes hydroelectric, solar, wind, and geothermal generation. EPA recognizes that promotion of energy efficiency and renewables can contribute to a cost-effective NO_X reduction strategy. As such, EPA encourages States in the NO_X SIP call region to consider including energy efficiency and renewables as a strategy in meeting their NO_X budgets. One way to achieve this goal is by including a provision within a State's NO_X Budget Trading Rule that allocates a portion of a State's trading program budget to implementers of energy efficiency and renewables projects that reduce energy-related NO_X emissions during the ozone season. Another is to include energy efficiency and renewables projects as part of a State's implementation plan.

The EPA is working to develop guidance on how States can integrate energy efficiency into their SIPs by both of these mechanisms. The guidance will present EPA's current thinking on the important elements to include in a functional system that allocates a portion of a State's trading program budget to implementers of energy efficiency and renewables projects within the context of the NO_X Budget Trading Program. In addition, EPA will issue guidance outlining procedures for including energy efficiency and renewables projects in a State's SIP as control strategies for achieving the State's NO_X budget, separate from the NO_X Budget Trading Program. EPA plans to issue these guidance documents in the Fall of 1998 so that they will be available to States early in their SIP planning process.

With respect to non-EGUs, individual States could choose to require emissions decreases from sources or source categories that EPA exempted from the budget calculations. For example, there are many large sources for which EPA lacked enough information to determine potential controls and emissions reductions; States may have access to such information and could choose to apply cost-effective controls. In addition, States could choose to regulate one or more of the non-EGU stationary sources or source categories which EPA had exempted because emissions were relatively low considering other source categories in the 23 jurisdictions. In individual States, emissions from such sources could be a high percentage of uncontrolled emissions and, thus, be subject to efficient, cost-effective control for that particular State. Further, States may take other approaches to developing their budgets, such as cutoffs based on horsepower rather than tons per day, since they might have access to data that EPA did not have for all 23 jurisdictions.

With respect to mobile sources, States could implement other NO_X control measures in lieu of the controls described earlier in this section. For example, vehicle inspection and maintenance programs can provide significant NO_X reductions from highway vehicles. Additional NO_X reductions can be obtained by opting into the reformulated gasoline program, by implementing measures to reduce the growth in VMT, and by implementing programs to accelerate retirement of older, higher-emitting highway vehicles and nonroad equipment.

5. Statewide Budgets

The revised Statewide budgets that reflect the changes to the base year inventory and growth factors for all sectors and the revised control levels for the non-EGU point source sector described above are shown in Table III–11. For the 23 jurisdictions combined, the budgets result in a 28 percent reduction from the base case. In the NPR and SNPR the percent reduction was 35 percent. The difference in the percent reduction is due to several factors. First, in the NPR and SNPR reductions from certain highway and nonroad controls were assumed to occur as a result of measures implemented between promulgation of this rule and 2007. These measures include National Low Emission Vehicle Standards, the 2004 Heavy-Duty Engine Standards, the Federal Small Engine Standards, Phase II, Federal Marine Engine Standards (for diesel engines of greater than 50 horsepower), Federal Locomotive Standards, and the Nonroad Diesel Engine Standards. These controls were reflected in the budget but were not included in the base case. For the final rule, EPA determined that these measures should be included in the base case, rather than the budgets, because the measures would be implemented even in the absence of this rulemaking. Based on the emission levels that were used in the SNPR, the effect of using this approach to setting the base case is to decrease the percent reduction from 35 percent to approximately 31 percent.

The additional change in the percent reduction (from 31 percent to 28 percent) is primarily due to EPA's decision not to assume controls for several non-EGU source categories and to change the level of control for those non-EGU categories for which controls are assumed. Although the overall percent reduction went from 35 percent to 28 percent, the difference between the budget proposed in the SNPR and the final budgets in today's notice is less than 3 percent.

TABLE III–11.—REVISED STATEWIDE NO_X Budgets

[Tons/season]

State	Base	Budget	Percent reduction
Alabama	218,610	158,677	27
Connecticut	43,807	40,57	37
Delaware	20,936	18,523	12
District of Columbia	6,603	6,792	¥3
Georgia	240,540	177,381	26
Illinois	311,174	210,210	32
Indiana	316,753	202,584	36
Kentucky	230,997	155,698	33
Maryland	92,570	71,388	23
Massachusetts	79,815	78,168	2
Michigan	301,042	212,199	30
Missouri	75,089	114,532	35
New Jersey	106,995	97,034	9
New York	190,358	179,769	6
North Carolina	213,296	151,847	29
Ohio	372,626	239,898	36
Pennsylvania	331,785	252,447	24
Rhode Island	8,295	8,31	30
South Carolina	138,706	109,425	21
Tennessee	252,426	182,476	28
Virginia	191,050	155,718	18
West Virginia	190,887	92,920	51
Wisconsin	145,391	106,540	27
Total	4,179,751	3,023,113	28

IV. Air Quality Assessment

A. Assessment of Proposed Statewide Budgets

In the SNPR, EPA documented the estimated ozone benefits of the proposed Statewide NO_X budgets based on an air quality modeling analysis. The major findings of that analysis are as follows:

(1) The emissions reductions associated with the proposed Statewide budgets are predicted to produce large reductions in both 1-hour and 8-hour concentrations in areas which currently violate the NAAQS and which would likely continue to have violations in the future without the SIP call budget reductions.

(2) Looking at individual ozone ''problem areas'' considered by OTAG shows similar results, based on the available metrics.

(3) Any ''disbenefits'' due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the benefits expected from these budgets.

(4) Even though the budgets are expected to reduce 1-hour and 8-hour ozone concentrations across all 23 jurisdictions, nonattainment problems requiring additional local control measures will likely continue in some areas currently violating the NAAQS. (63 FR 25903)

B. Comments and Responses

The EPA received numerous comments on the air quality modeling of the proposed NO_X budgets. The following is a summary of the main comments and EPA's responses.

Comment: Commenters stated that the emissions inventories used for modeling were flawed because EPA's projection of the base year emissions to 2007 improperly treated growth for certain electric generation units by growing these units beyond their design capacity.

Response: The EPA agrees with this comment and has revised the 2007 emissions projections for modeling to take this factor into account. For the modeling described in the SNPR, EPA applied State-level growth factors uniformly to existing sources in each State. This did not account for maximum capacity and could have resulted in sources being modeled with emissions that were higher than their actual capacity would allow. For the modeling described in this notice, EPA has revised the projection procedures to use IPM to allocate growth to existing units considering their design capacity. As described below, EPA has remodeled the 2007 Base Case and the Statewide budgets using this revised inventory and found that the conclusions from the revised runs do not differ from those based on the SNPR model runs of these budgets.

Comment: Commenters stated that EPA's modeling in the SNPR examined the impacts of the budgets applied regionwide (i.e., for each State for which a budget is required), rather than the impacts on downwind nonattainment of the budgets applied only in upwind States. Therefore, according to the commenters, this modeling is not useful for indicating the impact of the State budgets on downwind nonattainment or maintenance problems.

Response: The EPA is well aware that many States in the SIP Call region are both upwind and downwind States, that is, they are upwind of certain nonattainment areas and downwind from other States. For example, Pennsylvania is upwind of New York City, and emissions from Pennsylvania sources significantly contribute to this nonattainment problem; and

Pennsylvania is downwind of several States, emissions from which significantly contribute to Philadelphia's nonattainment problem.

The EPA is further aware that modeling analyses that evaluate emissions reductions in each State affected by today's rulemaking do not isolate the precise impact of emissions reductions from each upwind State on nonattainment in a State that is itself both an upwind and downwind State. That is, the emissions reductions in that upwind/downwind area impact its own nonattainment problems. To return to the example noted above, because emissions reductions in Pennsylvania affect Philadelphia's air quality, modeling Pennsylvania's emissions reductions along with emissions reductions in all other affected States does not isolate the impact of emissions reductions from States upwind of Pennsylvania on Philadelphia's air quality. As a result, EPA is aware that the regionwide modeling of different budget levels does not indicate the differential impact on downwind areas of higher budget levels as compared to lower budget levels in upwind areas.

Nevertheless, EPA believes that regionwide modeling of the State budgets is a useful indication of the overall impacts of various budget levels. Today's rulemaking requires regionwide emissions reductions, which will carry certain costs and will have certain impacts viewed on a State-by-State basis and on a regionwide basis. The multi-State budgets promulgated today mean that in a State that is both upwind and downwind of other States, such as Pennsylvania, the air quality will, in fact, be improved by the emissions reductions in upwind States and by the reductions within the States that are required to improve air quality further downwind. Thus, it is necessary to consider the upwind emissions reductions together with the downwind emissions reductions in order to fully evaluate the air quality impacts of the Statewide budgets. Regionwide modeling is the only available approach to indicate these ''real world'' impacts in individual States, as well as allow an assessment of those impacts in light of their costs. Accordingly, this modeling is useful in evaluating the overall impacts of the alternative budget levels considered in the course of the rulemaking. The EPA believes that a comparison of the overall impacts of alternative budget levels, in turn, serves as a means to confirm whether the budget levels promulgated in today's rulemaking yield meaningful air quality benefits. Moreover, EPA has conducted other modeling which indicates the impact of budget-level emissions on air quality downwind, as discussed below.

Comment: Commenters stated that EPA should have modeled the proposed budgets on a State-by-State basis in order to assess the downwind benefits of applying the budgets in each State.

Response: The EPA performed a multi-factor analysis to determine the amount of a State's emissions that significantly contribute to downwind nonattainment and what the resulting State budget should be. This is discussed in detail in Section II.C., Weight of Evidence Determination of Covered States. Specifically, EPA determined that emissions from all sources in certain States contribute to downwind problems, but that only a portion of those emissions—in some cases, a relatively small portion—may be reduced through highly cost-effective controls. The EPA established a budget for each State based on the elimination of these emissions. After EPA established the budgets, EPA performed air quality modeling to quantify the overall ozone benefits of the budgets applied in all upwind States on selected downwind areas. This modeling is described below. The EPA considered the results of this modeling as an additional piece of evidence in the analysis to confirm that the amount of emissions reductions from upwind States collectively provide meaningful reductions in nonattainment downwind.

For the purposes of this modeling it is sufficient to model the budgets collectively, and not State-by-State, to demonstrate that the intended benefits of the budgets are achieved.

Commenters who recommended State- by-State modeling generally argued that it would indicate that the reductions from a particular State would have a relatively small impact downwind, particularly compared to the impact of local reductions or reductions from other upwind States. In general, such a modeling result could stem from the relatively small amount of emissions reductions required of a particular upwind State under the SIP Call, due to EPA's decision to base the budgets on cost-effective controls rather than, more expensive controls. However, EPA's air quality modeling of the ambient impact of the required budgets in the upwind States on downwind nonattainment (discussed below) shows that even if the downwind ambient impact of the required reductions from a particular upwind State were small, that impact, when combined with the impact from the reductions required from other upwind States, provides meaningful downwind benefits. Ozone air quality problems are caused by the collective contribution from numerous sources over a large geographic area, so that it is appropriate to assess the impact of reductions from a particular upwind State in combination with reductions from other upwind States. The downwind air quality benefits from these upwind reductions confirm the appropriateness of the promulgated budgets.

Comment: Commenters stated that EPA should have modeled alternative control options to determine if less stringent controls, either applied uniformly or on a subregional basis (i.e., multi-State subregional variations in control levels), would provide air quality benefits essentially equivalent to EPA's proposal. In addition, commenters submitted a considerable number of new modeling analyses intended to show that (a) sufficient downwind ozone benefits can be achieved with control levels less stringent than those associated with EPA's proposal; (b) controls applied in certain upwind States, when examined on a State-by-State basis, do not provide ''significant'' benefits in any downwind nonattainment area; and/or (c) NO_X controls increase ozone locally in some areas and these increases are greater than the predicted decreases. In addition to new control strategy modeling, commenters submitted modeling that pertains to the finding of significant contribution. The EPA's responses to this modeling are discussed in Section II.C., Weight of Evidence Determination of Covered States and in the Response to Comment document.

Response: In response to the comments on the need to model alternative controls, EPA has modeled alternative budgets based on several EGU and non-EGU control options. For the most part, these alternative budgets were modeled regionwide in order to assess, as discussed above, the benefits considering both downwind and upwind emissions reductions, collectively. Further, as discussed below, EPA modeled several other types of scenarios including runs to assess the impacts of the proposal applied in upwind States on several downwind areas. The EPA's modeling analyses are summarized below and described in detail in the Air Quality Modeling TSD.

Regarding the new control strategy modeling submitted by commenters, EPA has reviewed this information in the same way it reviewed the new modeling on ''significant contribution'', as described in Section II.C., Weight of Evidence Determination of Covered States. Specifically, EPA reviewed the commenters' modeling to determine and assess (a) the technical aspects of the models that were applied; (b) the treatment of emissions inventories; (c) the types of episodes modeled; (d) the methods for aggregating, analyzing, and presenting the results; (e) the completeness and applicability of the information provided; and (f) whether the technical evidence supports the arguments made by the commenters. A summary of this review is discussed next. For the most part, the commenters used either the UAM–V model and/or the CAM_X model to assess the relative impacts of various NO_X control strategies. As discussed in Section II.C. Weight of Evidence Determination of Covered States, modeling results from both models are viewed by EPA as technically acceptable. Concerning the emissions used for modeling, most commenters stated that they used the EPA SNPR or IPM-derived 2007 Base Case emissions as a starting point for developing emissions for the control scenarios. However, the commenters did not provide emissions data summaries in order for EPA to confirm which inventories were used in the modeling. Also, the commenters did not document in detail how they applied the controls to the emissions inventory.

Most of the control strategy modeling submitted by commenters was performed for the July 1995 episode although a few commenters performed modeling for all four OTAG episodes and one commenter provided modeling for a non-OTAG episode in June of 1991. As discussed in Section II.C., and in the Response to Comment document, EPA's ability to fully evaluate and utilize the modeling submitted by commenters was hampered in some cases because only limited information on the results was provided.

The EPA considered the strengths and limitations in the commenters' modeling analyses in evaluating whether the technical evidence presented in the comments supports the arguments made by the commenters. A detailed review of the commenters' modeling is contained in the Response to Comment document. In general, this review indicates that (a) downwind ozone benefits increase as greater NO_X controls are applied to sources in upwind States, (b) emissions reductions at the level of the SIP Call, even when evaluated on an individual State-by-State basis, reduce ozone in downwind nonattainment areas, (c) the net benefits of NO_X control at the level of the SIP Call outweigh any local disbenefits, and (d) upwind NO_X reductions tend to mitigate local disbenefits in downwind areas. Thus, based on this evaluation, EPA generally found that the submitted modeling did not refute the overall conclusions EPA has drawn concerning the impacts of NO_X emissions in the relevant geographic areas. However, because the extent and level of detail in the information presented by the commenters was, in many cases, limited and/or qualitative, the EPA decided to model a number of alternative control scenarios for all four OTAG episodes.

The results of EPA's modeling of the impacts of alternative NO_X controls are described next.

C. Assessment of Alternative Control Levels

As indicated above, EPA has remodeled the Base Case and Statewide budgets using updated EGU emissions which do not exceed the capacity of individual units. In addition, EPA has performed modeling of various alternative EGU and non-EGU control options. Further, EPA has modeled the benefits in selected downwind areas of the budgets applied in upwind States. The results of EPA's modeling analyses are summarized below and described in more detail in the Air Quality Modeling TSD.

1. Scenarios Modeled

As part of EPA's assessment, a 2007 SIP Call Base Case (hereafter referred to as the ''Base Case'') and eight emissions scenarios were modeled, as listed in Table IV–1. The first four scenarios (i.e. ''0.25'', ''0.20'', ''0.15t'', and ''0.12'') were designed to evaluate alternative EGU and non-EGU controls applied uniformly in all 23 jurisdictions. For each of these four scenarios, EGU emissions were determined assuming a cap-and-trade program across all 23 jurisdictions. The 0.15t scenario reflects the SIP Call proposal for both non-EGU and EGU sources. Note that non-EGU controls were modeled at the level of the proposal for all scenarios except for the 0.25 scenario for which less stringent controls were assumed.

TABLE IV–1.—EMISSIONS SCENARIOS MODELED

Base Case:
- 2007 SIP Call Base Case [1]
  - Point Sources: CAA Controls.
  - Area Sources: OTAG ''Level 1'' Controls.
  - Highway Vehicles: OTAG ''Level 0'' Controls.

Control scenarios	Electricity generation units—EGUs	Non-EGU point sources [2]
0.25	0.25 lb/mmBtu, interstate trading	60% reduction for large sources.
0.20	0.20 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources[2].
0.15t	0.15 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources.
0.12	0.12 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources.
0.15nt	0.15 lb/mmBtu, intrastate trading	70% reduction for large sources, RACT for medium sources.

Downwind Scenarios for Analysis of ''Transport'':
(1) 0.15nt EGU and non-EGU controls in the Northeast [3]; 2007 Base Case emissions elsewhere.
(2) 0.15nt EGU and non-EGU controls in Georgia; 2007 Base Case emissions elsewhere.
(3) 0.15nt EGU and non-EGU controls in Illinois, Indiana, and Wisconsin; 2007 Base Case emissions elsewhere.

[1] See Table IV–2 for a listing of Base Case control measures.

[2] Reductions are from 2007 ''uncontrolled'' emissions. Non-EGU sources >250mmBtu/hr are considered as ''large''; sources <250mmBtu/hr, but >1tpd are considered as ''medium''. The non-EGU point source controls assumed for purposes of this modeling do not match the levels assumed for the purpose of calculating the final budgets.

[3] Northeast includes Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island.

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The EPA also modeled a 0.15 intrastate trading scenario, ''0.15nt'', which was constructed with EGU emissions that meet each State's budget without interstate trading. In developing the EGU emissions for this scenario, intrastate trading among sources in a State was allowed to occur. The benefits of the 0.15nt scenario compared to those from the 0.15t scenario were examined to determine whether an interstate trading program would affect the overall benefits of the proposal.

The last three scenarios in Table IV– 1 were designed to evaluate the downwind benefits resulting from reductions in transport due to the budgets in upwind States. Each of these scenarios constitutes a separate modeling run that applies the 0.15nt scenario in a different downwind area. For example, in the ''nt15NE'' scenario, the 0.15nt emissions budgets were applied only in those Northeast States subject to the SIP Call. The predictions from each of these three modeling runs for specific downwind areas were compared to the Base Case to estimate the impacts of the budgets applied only within the downwind area. The predictions from these three runs were then compared to the 0.15nt scenario across all 23 jurisdictions to estimate the additional benefits in each downwind area due to reductions in transport resulting from the budgets applied in both upwind and downwind States.

2. Emissions for Model Runs

As indicated in Table IV–1, Base Case emissions for area sources (including nonroad), highway vehicles, and non- EGU sources represent a combination of OTAG emissions data for various control levels. This includes CAA controls on non-EGU point sources, OTAG ''level 1'' controls on area sources, and ''level 0'' controls on highway vehicles. The control measures included in the Base Case for each source category are listed in Table IV–2. These modeling runs were performed before changes were made to the inventory in response to comments. For the 23 jurisdictions as a whole, the Base Case NO_X emissions that were modeled are 2 percent higher than the final Base Case emissions that reflect changes made in response to comments.

TABLE IV–2.—2007 SIP CALL BASE CASE CONTROLS

EGUs:
- Title IV Controls [phase 1 and 2].
- —250 Ton PSD and NSPS.
- —RACT & NSR in non-waived NAAs.

Non-EGU Point:
- —NO_X RACT on major sources in non-waived NAAs.
- —250 Ton PSD and NSPS.
- —NSR in non-waived NAAs.
- —CTG and Non-CTG VOC RACT at major sources in NAAs and OTR.
- —New Source LAER.

Stationary Area:
- —Two Phases of VOC Consumer and Commercial Products and One Phase of Architectural Coatings controls.
- —VOC Stage 1 and 2 Petroleum Distribution Controls in NAAs.
- —VOC Autobody, Degreasing and Dry Cleaning controls in NAAs.

Nonroad Mobile:
- Fed Phase II Small Eng. Stds.
- —Fed Marine Eng. Stds.
- —Fed Nonroad Heavy-Duty (≤=50 hp) Engine Stds—Phase 1.
- —Fed RFG II (statutory and opt-in areas).
- —9.0 RVP maximum elsewhere in OTAG domain.
- —Fed Locomotive Stds (not including rebuilds).
- —Fed Nonroad Diesel Engine Stds—Phases 2 and 3.

Highway Vehicles:
- —National LEV.
- —Fed RFG II (statutory and opt-in areas).
- —9.0 RVP maximum elsewhere in OTAG domain.
- —High Enhanced I/M (serious and above NAAs).
- —Low Enhanced I/M for rest of OTR.
- —Basic I/M (mandated NAAs).
- —Clean Fuel Fleets (mandated NAAs).
- —On-board vapor recovery.
- —HDV 2 gm std.

Rate of Progress Requirements:
- —Effectively, ROP through 1999.

Note that area and mobile source emissions were held constant at Base Case levels in all scenarios. The Base Case emissions for EGUs were obtained from simulations of IPM which projected 1996 electric generation to 2007 based on economic assumptions, unit specific capacity, and the requirements in Title I and Title IV of the CAA. The Base Case emissions that were modeled for the EGU sector are 4 percent higher than the final Base Case emissions for this sector. The EGU emissions estimates for each of the control scenarios in Table IV–1 were also derived using the IPM. Table IV–3 summarizes the emissions reductions provided by the control scenarios compared to the Base Case. The development of emissions data for air quality modeling is further described in the Air Quality Modeling TSD.

TABLE IV–3.—SUMMARY OF NO_X EMISSIONS REDUCTIONS

Region [1]	0.25	0.20	0.15t	0.12	0.15nt
Percent Reduction in Point Source NO_X Emissions From 2007 SIP Call Base Case					
Northeast	29	39	49	52	46
Midwest	40	51	59	65	58
Southeast	35	49	54	61	56
SIP Call [2]	37	48	57	62	57
Percent Reduction in Total NO_X Emissions From 2007 SIP Call Base Case					
Northeast	13	18	22	24	21
Midwest	22	28	33	36	32
Southeast	19	26	29	32	30
SIP Call [2]	20	26	30	33	30

[1] The Northeast includes Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island; the Midwest includes Illinois, Indiana, Kentucky, Michigan, Missouri Ohio, West Virginia, and Wisconsin; the Southeast includes Alabama, Georgia, North Carolina South Carolina, Tennessee and Virginia.
[2] ''SIP Call'' includes the total percent reduction over all 23 jurisdictions subject to budgets as part of this notice.

3. Modeling Results

The EPA applied UAM–V for each of the four OTAG episodes to simulate ozone concentrations for the Base Case and each scenario. The results for the uniform regionwide scenarios are presented first. This is followed by the results comparing interstate and intrastate trading. The results for the assessment of overall downwind benefits of the budgets applied in upwind States is presented last.

The analysis of model predictions focused 1-hour daily maximum values and 8-hour daily maximum values predicted for all 4 episodes. The rationale for analyzing the model predictions in this way is discussed in Section II.C. Each of the control scenarios was evaluated using the four ''metrics'' listed in Table IV–4. Note that the model predictions used in calculating the metrics were restricted to those 1-hour values >=125 ppb and 8-hour values >=85. Model predictions less than these concentrations were not included in the analysis.

TABLE IV–4.—AIR QUALITY METRICS

Metric 1: Exceedances	The number of values above the concentration level of NAAQS.[1]
Metric 2: Ozone Reduced-ppb	The magnitude and frequency of the ''ppb'' reductions in ozone.
Metric 3: Total ppb Reduced	The total ''ppb'' reduced by a given scenario, not including that portion of the reduction that occurs below the level of the NAAQS.
Metric 4: Population-Weighted Total ppb Reduced.	The same as Metric 3, except that the ozone reductions are weighted by the population in the grid cell in which the reductions occur.

[1] 1-hour values >=125 ppb; 8-hour values >=85 ppb.

A full description of these metrics and the procedures for selecting ''nonattainment'' receptors for calculating the metrics can be found in the Air Quality Modeling TSD. In brief, ''nonattainment'' receptors for the 1-hour analysis include those grid cells that (a) are associated with counties designated as nonattainment for the 1-hour NAAQS and (b) have 1-hour Base Case model predictions >=125 ppb. These grid cells are referred to as ''designated plus modeled'' nonattainment receptors. Using these receptors, the metrics were calculated for each 1-hour nonattainment area as well as for each State. To calculate the metrics by State, the ''nonattainment'' receptors in that State were pooled together.

For the 8-hour analysis, ''nonattainment'' receptors include those grid cells that (a) are associated with counties currently violating the 8-hour NAAQS and (b) have 8-hour Base Case model predictions >=85 ppb. These grid cells are referred to as ''violating plus modeled'' nonattainment receptors. The metrics were calculated on a State- by-State basis for the 8-hour analyses.

In general, the four metrics lead to similar overall conclusions. The results for the full set of receptor areas (i.e., ''designated plus modeled'' for the 1-hour NAAQS and ''violating plus modeled'' for the 8-hour NAAQS) are provided in the Air Quality Modeling TSD for all four metrics. In this preamble, Metrics 1 and 3 are presented to illustrate the results.

a. Impacts of Alternative Controls. The impacts on ozone concentrations of the 0.15t scenario and each of the alternative scenarios are provided by region (i.e., Midwest, Southeast, and Northeast) in Tables IV–5 and IV–6 for Metrics 1 and 3, respectively. The complete set of data for individual States and 1-hour nonattainment areas is provided in the Air Quality Modeling TSD. Table IV–5 shows the percent reduction in the number of exceedances across all four episodes between each control scenario and the Base Case. Table IV–6 shows the percent reduction in total ozone above the NAAQS provided by each scenario, compared to the total ozone above the NAAQS in the Base Case.

TABLE IV–5.—RESULTS FOR METRIC 1: NUMBER OF EXCEEDANCES

	0.25	0.20	0.15t	0.12	0.15nt
Percent Reduction in the Number of Exceedances 1-Hour Daily Maximum >=125 ppb					
Midwest	25	32	38	43	38
Southeast	23	33	34	40	36
Northeast	24	31	36	39	36
SIP Call Total	24	31	36	40	37
Percent Reduction in the Number of Exceedances 8-Hour Daily Maximum >=85 ppb					
Midwest	35	44	50	54	49
Southeast	30	40	46	51	48
Northeast	26	34	41	44	41
SIP Call Total	30	39	45	49	45

TABLE IV–6.—RESULTS FOR METRIC 3: TOTAL "PPB" REDUCED

	0.25	0.20	0.15t	0.12	0.15nt
Total "ppb" Reduced Compared to the Total "ppb" Above NAAQS in Base Case [1] 1-Hour Daily Maximum >=125 ppb					
Midwest	31	39	45	49	44
Southeast	27	37	39	44	41
Northeast	25	32	37	40	37
SIP Call Total	27	35	40	43	40
Total "ppb" Reduced Compared to the Total "ppb" Above NAAQS in Base Case 8-Hour Daily Maximum >=85 ppb					
Midwest	35	42	48	52	47
Southeast	33	44	49	53	50
Northeast	28	37	43	46	43
SIP Call Total	31	40	46	50	46

[1] The values in this table were calculated by dividing the Total "ppb" Reduced in the control scenario by the Total "ppb" above the NAAQS in the Base Case. These values represent the percent of total ozone above the NAAQS in the Base Case that is reduced by the control scenario.

The results indicate that the 0.15t scenario provides substantial reductions in both 1-hour and 8-hour ozone concentrations in all three regions.

In the Midwest the 0.15t scenario provides a 38 percent reduction in 1-hour exceedances and a 45 percent reduction in ''total ozone'' >=125 ppb. The regionwide Midwest reductions in 8-hour exceedances and ''total ozone'' >=85 ppb are 45 percent and 50 percent, respectively. Considering individual 1-hour nonattainment areas in this region, the reduction in exceedances due to the 0.15t controls are 36 percent over Lake Michigan,[61] 73 percent in Southwest Michigan, and 54 percent in Louisville. The corresponding reductions in ''total ozone'' >=125 ppb are 44 percent over Lake Michigan, 81 percent in southwest Michigan, and 64 percent in Louisville. The results for other areas are contained in the Air Quality Modeling TSD.

In the Southeast, 1-hour exceedances are reduced by 39 percent and the ''total ozone'' >=125 ppb by 34 percent. Considering individual nonattainment areas in the Southeast, the 0.15t scenario provides a 36 percent reduction in 1-hour exceedances in Atlanta and a 39 percent reduction in exceedances in Birmingham. The reduction in ''total ozone'' >=125 ppb is 41 percent in Atlanta and 54 percent in Birmingham. The overall regionwide ozone benefits across the Southeast are also large for the 8-hour NAAQS. For example, the number of 8-hour exceedances in this region is reduced by 46 percent with the 0.15t scenario.

In the Northeast, 0.15t provides a 37 percent reduction in 1-hour exceedances and a 34 percent reduction in ''total ozone'' >=125 pp. For individual nonattainment areas in the Northeast, the reductions in both Metrics 1 and 3 range from approximately 25 percent in Washington, DC up to 100 percent in Pittsburgh. For the serious and severe 1-hour nonattainment areas along the Northeast Corridor from Washington, DC to Boston, the 1-hour reductions vary from city to city, but are generally in the range of 25 percent to 55 percent. The regionwide reductions in 8-hour exceedances and ''total ozone'' >=85 ppb in the Northeast are above 40 percent.

In general, results from the scenarios evaluated demonstrate that the larger the reduction in NO_X emissions, the greater the overall ozone benefit. As indicated in Table IV–5 and IV–6, the 0.25 and 0.20 scenarios generally do not provide the same level of reduction as the 0.15t scenario in any of the three regions, whereas the 0.12 scenario provides additional ozone benefits beyond 0.15t in all three regions. Also, the results indicate that even with the most stringent control option considered, nonattainment problems requiring additional local controls may continue in some areas currently violating the NAAQS.

The impact on ozone reductions of a trading program versus meeting the budgets in each State can be seen by comparing the results for the 0.15t and 0.15nt scenarios. The data in Tables IV– 5 and IV–6 indicate that there is no overall loss of ozone benefits for either 1-hour or 8-hour concentrations across the 23 jurisdictions due to trading. On a regional basis, the benefits of interstate and intrastate trading at the 0.15 control level are essentially the same in the Northeast and Midwest and slightly less with interstate trading in the Southeast.

[61] The rationale for analyzing the impacts over Lake Michigan is discussed in Section II.C, Weight of Evidence Determination of Covered States.

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As indicated in the summary of comments, several commenters stated that there would be local disbenefits due to the EPA proposal that would outweigh any benefits. The modeling runs discussed here shed light on the issue. Of the four metrics examined by EPA, Metrics 3 and 4 (i.e., ''Total ppb Reduced'' and ''Population-Weighted Total ppb Reduced'') are most appropriate for identifying any net disbenefits because the ozone decreases and any increases (disbenefits) are considered in calculating each of these metrics. The metrics will have negative values for situations in which the total disbenefits are greater than the total benefits. The EPA examined the 1-hour estimates for these metrics for each 1-hour nonattainment area and the 8-hour estimates by State to identify any areas in which the modeling indicated a net disbenefit. The results indicate that the only net disbenefit predicted in any of the scenarios was in Cincinnati for the 1-hour NAAQS. However, these disbenefits occurred only in the 0.25 and 0.20 scenarios. In the 0.15t scenario, there is a net 32 percent benefit in Cincinnati with Metric 3 and a net benefit of 23 percent with Metric 4. There were no net Statewide 8-hour disbenefits in any of the scenarios examined by EPA.

b. Impacts of Upwind Controls on Downwind Nonattainment . The impacts of the budgets applied in upwind States on downwind ozone in the (a) the Northeast, (b) Georgia, and (c) Illinois-Indiana-Wisconsin, were evaluated by comparing the 0.15nt scenario to the three downwind transport assessment scenarios listed in Table IV–1. In each of these three scenarios, EPA modeled the 0.15nt option in one of the downwind areas with the Base Case emissions applied in the rest of the OTAG region.[62] The results of each downwind control run were compared to the Base Case in order to assess the benefits of the controls applied within those areas (i.e., the downwind areas). Similarly, the predictions for the 0.15nt regionwide scenario were compared to the Base Case to estimate the benefits in each area of the downwind plus upwind controls. The benefits of the upwind controls were determined by calculating the difference between the benefits of the downwind controls compared to the benefits of the downwind plus upwind controls. The results are provided in Table IV–7. The following is an example of how the benefits of upwind controls were calculated for Metric 1 (i.e., number of exceedances). In the Northeast, there were 1052 grid-day exceedances of the 1-hour NAAQS predicted in the Base Case scenario. In the downwind control scenario (i.e., 0.15nt applied in the Northeast only), the number of exceedances declined to 827 grid-days which represents a 21 percent reduction in exceedances from the Base Case due to controls in the Northeast. In the downwind plus upwind scenario, the number of 1-hour exceedances declined even further to 670 grid-days which is a 36 percent reduction from the Base Case. Therefore, the upwind controls provide a 15 percent reduction in 1-hour exceedances in the Northeast (i.e., 36 percent versus 21 percent).

For Metric 3 (i.e., Total ''ppb'' Reduced), the impact of upwind controls on downwind ozone was determined using two approaches. The first approach is similar to the procedures followed described above for exceedances. For example, in the Northeast the total ppb >=125 ppb (across all grids and days) in the Base Case was 14,724 ppb. In the downwind control scenario the total ppb reduced by these controls was 3289 ppb which represents a 22 percent reduction (i.e., 3289 ppb divided by 14,724 ppb) in total ppb >=125 ppb. In the downwind plus upwind control scenario, the total ppb reduced was 5500 ppb which represents a 37 percent reduction in total ppb >=125 ppb in the Base Case. Therefore, the upwind controls provide a 15 percent reduction in total ppb >=125 ppb (i.e., 37 percent versus 22 percent). The results for Metric 3 calculated using this first approach are presented in Table IV–7.

A second approach to analyze the benefits of upwind controls using Metric 3 is to determine the fraction or percentage of the total reduction from downwind plus upwind controls that comes from just the upwind controls. This is determined by first subtracting the ppb reduced by downwind controls from the ppb reduced by downwind plus upwind controls. This difference provides an estimate of the portion of the reduction due to upwind controls. Then, the portion of the reduction due to upwind controls is divided by the reduction from downwind plus upwind controls to estimate the percent of reduction due to the upwind controls only. For example, in the Northeast the 1-hour total ppb reduced by the downwind plus upwind controls is 5500 ppb and the total ppb reduced by the downwind controls is 3289 ppb. The difference (2211 ppb) is the estimated amount of reduction due to upwind controls. Thus, in this example, the upwind controls provide 40 percent (i.e., 2211 ppb divided by 5500 ppb) of the total ppb reduction in the downwind plus upwind regionwide scenario. The results for Metric 3 using this second approach for estimating the impacts of upwind controls are provided in Table IV–8.

	1-hour daily max			8-hour daily max		
	DW [1]	DW + UW [1]	UW [1]	DW	DW + UW	UW
Percent Reduction in Exceedances						
Northeast	21	36	15	18	40	22
Lake MI	29	36	7	11	17	6
IL/IN/WI	35	50	15	27	57	30
Atlanta	30	39	9	[2] NA	NA	NA
Georgia [3]	30	39	9	15	27	12
Percent Reduction in Total ''ppb'' Above the NAAQS						
Northeast	22	37	15	23	43	20
Lake MI	39	44	5	20	28	8
IL/IN/WI	17	33	16	32	62	30
Atlanta	37	43	6	NA	NA	NA

[62] As described in the Air Quality Modeling TSD, emissions from the intrastate trading scenario rather than the interstate trading scenario were used for the analysis of upwind controls in order to avoid any potentially confounding effects of small changes in the downwind emissions between the downwind control scenario and the downwind plus upwind control scenario due to interstate trading.

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	1-hour daily max			8-hour daily max		
	DW [1]	DW + UW [1]	UW [1]	DW	DW + UW	UW
Georgia	37	43	6	25	35	10

[1] ''DW'' denotes the reductions due to the downwind controls; ''DW + UW'' denotes the reductions due to controls applied regionwide in upwind plus downwind areas; and ''UW'' denotes the incremental additional reduction in exceedances.
[2] NA: The metrics for the 8-hour NAAQS were not calculated for individual 1-hour nonattainment areas.
[3] The 1-hour results for Georgia are the same as for Atlanta because Atlanta is the only 1-hour nonattainment area in that State.

TABLE IV–8.—PERCENT OF THE TOTAL PPB ABOVE THE NAAQS THAT IS REDUCED DUE TO UPWIND CONTROLS

	1-hour daily max (percent)	8-hour daily max (percent)
Northeast	40	48
Lake MI	12	27
IL/IN/WI	49	48
Atlanta	14	NA
Georgia	14	28

In the following discussion of the impacts of upwind controls on ozone in the three downwind areas, the results for Metric 3 focus on the second approach for calculating upwind impacts using this metric since the results based on the first approach are similar to those for Metric 1, as indicated in Table IV–7.

In the Northeast, the upwind controls provide a 15 percent reduction in 1-hour exceedances and a 22 percent reduction in 8-hour exceedances. The results in Table IV–8 indicate that upwind controls provide 40 percent or more of the total ppb reduction from the downwind plus upwind control scenario for both the 1-hour and 8-hour NAAQS. Considering the results for several 1-hour nonattainment areas in the Northeast, the upwind controls reduce the number of 1-hour exceedances by 21 percent in Baltimore, 12 percent in Philadelphia, 12 percent in New York City, 19 percent in Greater Connecticut, and 3 percent in Boston. The percent of the total ppb reduction from the downwind plus upwind controls that is due to the upwind controls alone is 48 percent in Baltimore, 29 percent in Philadelphia, 38 percent in New York City, 47 percent in Connecticut, and 25 percent in Boston. The results for all of the Northeast 1-hour nonattainment areas are provided in the Air Quality Modeling TSD.

The impacts of upwind controls on nonattainment in Georgia were examined using the 0.15nt scenario in Georgia versus the Base Case scenario and the scenario with 0.15nt applied regionwide. The results, as shown in Table IV–7, indicate that the upwind controls are predicted to reduce the number of 1-hour exceedances in Atlanta by 9 percent. Also, in Atlanta, 14 percent of the 1-hour total ppb above the NAAQS reduced by the downwind plus upwind regionwide scenario is due to the controls applied in upwind States. For the 8-hour NAAQS, the upwind controls provide a 12 percent reduction in 8-hour exceedances within the State of Georgia. The upwind controls provide 28 percent of the total ppb reduction in the downwind plus upwind regionwide control scenario. To assess the benefits in Illinois-Indiana-Wisconsin due to upwind controls, EPA examined the data for the Lake Michigan receptor area and for the three States, combined. The discussion of results focuses on the Lake Michigan receptor area. The data for this area and the three States are provided in Table IV–7. For the Lake Michigan receptor area, there is a 7 percent reduction in 1-hour exceedances and a 6 percent reduction in 8-hour exceedances due to upwind controls. The upwind controls provide 12 percent of the total 1-hour reduction and 27 percent of the total 8-hour reduction that results from the downwind plus upwind regionwide controls. In Illinois, Indiana, and Wisconsin, the reduction in 1-hour and 8-hour exceedances due to upwind controls are larger than over Lake Michigan (i.e., 15 percent and 30 percent for 1-hour and 8-hour exceedances, respectively). The upwind controls provide nearly 50 percent of the total ppb reductions associated with the downwind plus upwind regionwide control scenario for both the 1-hour and 8-hour NAAQS.

Based on the results discussed above, EPA believes that the controls in today's rulemaking applied in upwind areas will reduce the number of 1-hour and 8-hour exceedances in downwind nonattainment areas. The analysis indicates that in downwind areas, a substantial portion of the 1-hour and 8- hour ozone reductions provided by the regionwide application of these controls are due to those controls in upwind areas.

c. Summary of Findings. The EPA has performed an air quality assessment to estimate the ozone benefits of the proposal and several alternative uniform regionwide control levels. In addition, EPA examined the overall benefits in several major downwind nonattainment areas of the application of the proposal in upwind States. The results of EPA's assessment corroborate and extend the findings presented in the SNPR. The major findings are as follows: (1) The NO_X emissions reductions associated with the proposed Statewide budgets are predicted to produce large reductions in (a) 1-hour concentrations >=125 ppb in areas which are currently nonattainment for the 1-hour NAAQS and which would likely continue to have a 1-hour nonattainment problem in the future without the SIP call budget reductions, and (b) 8-hour concentrations >=85 ppb in areas which currently violate the 8-hour NAAQS and which would likely continue to have an 8-hour ozone problem in the future without the SIP call budget reductions.

(2) The more NO_X emissions are reduced, the greater the benefits in reducing ozone concentrations. There does not appear to be any ''leveling off'' of benefits within the range of NO_X reductions associated with EPA's proposal. That is, NO_X reductions at control levels less than EPA's proposal provide fewer air quality benefits than the proposal and NO_X reduction greater than the proposal provide more air quality benefits.

(3) Any disbenefits due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the benefits expected from these budgets.

(4) There are likely to be benefits in major nonattainment areas due to the downwind application of controls in the proposed budgets. Reductions in ozone transport associated with the collective application of the budgets in upwind States are expected to provide substantial ozone benefits in downwind areas, beyond what is provided by the budgets applied in the downwind areas alone. Together, the downwind reductions and transport reductions from upwind controls will provide significant progress toward attainment in major nonattainment areas within the OTAG region. However, even with the most stringent control option considered, nonattainment problems requiring additional local control measures may continue in some areas currently violating the NAAQS.

V. NO_X Control Implementation and Budget Achievement Dates

A. NO_X Control Implementation Date

In the NPR, the EPA proposed to mandate NO_X emissions decreases in each affected State leading to a budget based on reductions to be achieved from both Federal and State measures. The EPA further proposed that the required SIP revisions for achieving the portion of the NO_X reduction from State measures be implemented by no later than September 2002. The EPA also requested comment on a range of compliance dates between September 2002 and September 2004.

The EPA stated that this range of compliance dates is consistent with the requirement for severe 1-hour nonattainment areas to attain the standard no later than 2005 (for severe- 15 areas) or 2007 (for severe-17 areas). With respect to the 8-hour ozone standard, EPA stated that the CAA provides for attainment within 5 years of designation as nonattainment, which must occur no later than July 2000, with a possible extension of up to 10 years following designation as nonattainment. The EPA stated that the range of implementation dates—from September 2002 to September 2004—is consistent with the attainment time frames for the 8-hour standard (62 FR 60328–29). For the reasons described in Section III, below, the applicable attainment date for all affected downwind areas is ''as expeditiously as practicable,'' but no later than certain prescribed dates. In many cases, the date for achieving the upwind reductions will make the difference as to when downwind States will attain. Thus, it is appropriate for EPA to require the upwind reductions to be achieved as expeditiously as practicable. Subsection 1., below, analyzes the earliest date feasible for achieving the upwind reductions.

1. Practicability

After reviewing the comments and analyzing the feasibility of implementing the NO_X controls assumed for purposes of developing the State emissions budgets, as well as other measures which States may choose to rely on to meet the rule, the EPA is today determining that the required implementation date must be by no later than May 1, 2003. The Agency received many comments on the feasibility of installing appropriate control technology by 2003, and the succeeding paragraphs address many of the significant comments submitted on this topic.

Some commenters asserted that a compliance deadline of September 2002 is infeasible for completing the installation of the assumed NO_X controls. Some of these commenters argued that there are not enough trained workers, engineering services or materials and equipment to install NO_X controls by the September 2002 deadline. Other commenters expressed concern that utilities will not have sufficient time to install NO_X controls without causing electrical power outages; these commenters stated that such power outages would have adverse impacts on the reliability of the electricity supply. Commenters also expressed concern that retrofitting NO_X controls would require increasing the operation of less efficient units, which would increase compliance costs.

In response to these comments, the Agency has conducted a detailed examination of the feasibility of installing the NO_X controls that EPA assumed in constructing the emissions budgets for the affected States (hereinafter, the ''assumed control strategy''). See the technical support document ''Feasibility of Installing NO_X Control Technologies By May 2003,'' EPA, Office of Atmospheric Programs, September 1998. The Agency's findings are summarized below. Based on these findings, the EPA believes that the compliance date of May 1, 2003 for NO_X controls to be installed to comply with the NO_X SIP call is a feasible and reasonable deadline. The Agency is also providing some compliance flexibility to States for the 2003 and 2004 ozone seasons by establishing State compliance supplement pools as described above in Section III.F.6.

The EPA's projections for the assumed control strategy include post-combustion controls (Selective Catalytic Reduction [SCR] and Selective Noncatalytic Reduction [SNCR]) and combustion controls (e.g., low NO_X burners, overfire air, etc.)

a. Combustion Controls. In general, the implementation of combustion controls should be readily accomplished by May 1, 2003 for the following reasons. First, there is considerable experience with implementing combustion controls. Combustion control retrofits on over 230 utility boilers, accounting for over 75 GWe of capacity under the title IV NO_X program, took place within 4 years (i.e., from 1992 through 1995). Moreover, the combustion retrofits under Phase I of the Ozone Transport Commission's Memorandum of Understanding were completed in the same time frame. As a result of this experience, the sources and permitting agencies are familiar with the installation of combustion controls. This familiarity should result in relatively short time frames for completing technology installations and obtaining relevant permits.

Second, combustion controls are constructed of commonly available materials such as steel, piping, etc., and do not require reagent during operation. Therefore, the EPA does not expect delays due to material shortages to occur at sites implementing these controls.

Third, there are many vendors of combustion control technology. These vendors should have ample capacity to meet the NO_X SIP call needs because they were able to satisfy significant installation needs during the period 1992 through 1995, as mentioned above. Since then these vendors have had relatively few installation needs to fill.

Therefore, it is reasonable to expect that implementation of post-combustion controls, not combustion controls, would determine the schedule for implementing all of the projected NO_X controls.

b. Post-Combustion Controls. Tables V–1 and V–2 present the Agency projections of how many electricity generating units and industrial sources, respectively, would need to be retrofitted with post-combustion NO_X controls under the assumed control strategy.

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TABLE. V–1.—ELECTRICITY GENERATING UNITS

NO_X Control	Projected No. of installations
Coal SCR	142
Coal SNCR	482
Oil/gas SNCR	15
Total	639

TABLE. V–2.—NON-ELECTRICITY GENERATING UNITS

NO_X Control	Projected No. of installations
SCR on coal-fired sources	55
SCR on oil/gas-fired sources	225
SCR on other sources	1
Total	281
SNCR on coal-fired sources	195
SNCR on oil/gas-fired sources	0
SNCR on other sources	40
Total	235

There are three basic considerations related to implementation of post-combustion controls (SCR and SNCR) by the compliance date: (1) Availability of materials and labor, (2) the time needed to implement controls at plants with single or multiple retrofit requirements, and (3) the potential for interruptions in power supply resulting from outages needed to complete installations.

The EPA examined each of these considerations. An adequate supply of off-the-shelf hardware (such as steel, piping, nozzles, pumps, soot blowers, fans, and related equipment), reagent (ammonia and urea), and labor would be available to complete implementation of post-combustion controls projected under the assumed control strategy.

However, the catalyst used in the SCR process is not an off-the-shelf item and, therefore, requires additional consideration. Based on the projections shown in the tables above, the EPA estimates that about 54,000 to 90,000 m^3 of catalyst may be needed in SCR installations. The EPA has found that currently the catalyst suppliers can supply about 43,000 to 67,000 m^3 of catalyst per year. However, of this supply about 5,000 to 8,000 m^3 of catalyst per year is needed to meet the requirements of the existing worldwide SCR installations. Based on these estimates, the EPA conservatively concludes that adequate catalyst supply should be available if SCR installations were to occur over a period of two years or more.

In addition, in comments to EPA's proposed NO_X reduction program, the Institute of Clean Air Companies (ICAC) stated that more than sufficient vendor capacity existed to supply retrofit SCR catalyst to the sources that would be controlled by SCR under the assumed control strategy.

Implementation of a NO_X control technology on a combustion unit involves conducting facility engineering review, developing control technology specifications, awarding a procurement contract, obtaining a construction permit, completing control technology design, installation, testing, and obtaining an operating permit. The EPA evaluated the amount of time potentially needed to complete these activities for a single unit retrofit and found that about 21 months would be needed to implement SCR while about 19 months would be needed to implement SNCR.

The EPA examined several particularly complicated implementation efforts to assure an accurate and realistic estimate of the time needed to install SCR and SNCR. The EPA examined the data and determined that the assumed control strategy might lead one plant to choose to install a maximum of 6 SCRs. In another instance, a different plant might choose to install a maximum of 10 SNCRs under the assumed control strategy. The estimated total time needed to complete these installations is 34 months for 6 SCR systems and 24 months for 10 SNCR systems.

Finally, the EPA examined the impact(s) that outages required for connecting NO_X post-combustion controls to EGUs could potentially have on the supply of electricity and on the cost of this rule. The EPA has found that, generally, connections between a NO_X control system and a boiler can be completed in 5 weeks or less. This connection period has been accounted for in both the single and multi-unit implementation times presented in the previous paragraph. On an EGU, the connection would have to be completed during an outage period in which the unit is not operational. The EPA's research reveals that currently, on average, about 5 weeks of planned outage hours are taken every year at an electricity generating unit. Therefore, the EPA expects that connection between a NO_X control system and such a unit would be completed during one of these planned outages.

Results of EPA's analyses reflect that, even if all of the post-combustion controls projected in Table V–1 for the EGUs were to be connected to these units in one single year, no disruption in the supply of electricity would occur. If each of these plants takes the five week outage in a single block of time, no cost increase is expected to occur. However, if a plant divides the five week outage into two or more periods, a cost increase of less than one-half of one percent may be expected. See the technical support document ''Feasibility of Installing NO_X Control technologies By May 2003,'' EPA, Office of Atmospheric Programs, September 1998.

Based on the estimated timelines for implementing NO_X controls at a plant and availability of materials and labor, the EPA estimates that the NO_X controls in the assumed control strategy (which is one available method for achieving the required NO_X reductions in each covered State) could be readily implemented by September 2002, without causing an adverse impact on the electricity supply or on the cost of compliance. The EPA bases this conclusion on its analysis that the most complex and time-consuming implementation effort—one involving 6 SCR systems—would take 34 months, and that all of the controls could be installed within this period without causing any disruptions in the supply of electricity.

Further, the EPA notes that the September 27, 1994 OTC NO_X Memorandum of Understanding (MOU) provides that large utility and nonutility NO_X sources should comply with the Phase III controls by the year 2003. The levels of control in the MOU are 75 percent or 0.15 lb/10^6 btu in the inner and outer zones of the Northeast OTR, levels comparable to the controls assumed in setting the budget for today's rulemaking. Moreover, several States in the Northeast OTR have submitted SIP revisions implementing this level of emissions reductions from NO_X sources in those States by May 1, 2003. This further supports the feasibility of the May 1, 2003 implementation date for these controls.

The EPA has determined that States would have sufficient time to implement other NO_X control measures in lieu of the boiler controls described above. For example, vehicle I/M programs have historically required no more than two years to implement, including the time needed to pass enabling State legislation and to construct the necessary emission testing facilities. The time required to implement measures to reduce VMT depends on the nature of the measure, but many VMT reduction measures require no more than one or two years to implement. State opt-ins to the RFG program have generally required less

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than one year to implement. Even if the EPA were to determine that supply considerations warranted a delay in implementing the opt-in request, the delay cannot exceed two years.

States can also take advantage of the NO_X-reducing benefits that energy efficiency and renewables projects provide, many of which could be developed in less than three years and incorporated into a SIP. Examples of efficiency/renewables projects that have been accomplished within a 3-year time frame and have resulted in significant NO_X reductions include reducing boiler fuel use by utilizing waste heat, implementing short-term steam trap maintenance and inspection programs, and undertaking building upgrades using EPA's Energy Star Buildings approach.

2. Relationship to SIP Submittal Date

Under this rule, as explained in Section B. below, States are required to submit revised SIPs by September 30, 1999. Commenters have suggested that based on the requirements of this rulemaking, sources in these States would need to begin early planning of compliance strategies before the September 30, 1999 date. The EPA disagrees. The EPA's technical analysis described above indicates that if these sources begin planning and specification of controls by even as late as April 2000, then they would be able to complete control technology implementation by May 1, 2003.

3. Rationale

To assure adequate lead-time for implementation of controls, the EPA has moved the compliance deadline from the proposed date of September 2002 in the NPR to May 1, 2003. Since the ozone seasons in areas in the eastern U.S. end in the fall and begin in the spring, setting the implementation date for May 1, 2003 will provide sources 7–8 additional months for implementing control requirements while not undermining the ability of areas to attain. The additional implementation time will occur during the cooler months of the year, a time when ozone exceedances generally do not occur. Thus, with either the September 2002 implementation date or the May 1, 2003 implementation date, the 2003 ozone season would be the first to benefit from full implementation of the SIP call reductions.

Several commenters contend that EPA does not have the authority to establish the compliance date. Since section 110(a)(2)(D)(i) is silent as to the implementation schedule for measures to prevent significant contribution, the EPA disagrees that the statute prohibits the EPA from establishing an implementation date for control measures that will achieve the reductions established by the SIP call. Thus, the EPA must look to the other provisions in the CAA, the legislative history, and the specific facts of today's rule to determine whether it is reasonable for the Agency to set the implementation date for the control measures. Furthermore, for the reasons provided in this Section, the EPA believes it is necessary to use its general rulemaking authority under section 301(a) to establish the latest date for implementation through a rule in order to ensure that downwind areas attain the standard as expeditiously as practicable and that areas continue to make progress toward attaining the NAAQS. *See NRDC* v. *EPA* , 22 F.3d 1125, 1146–48 (D.C. Cir. 1994).

With respect to the facts of this particular situation, this SIP call entails a complex analysis of the interstate transport of NO_x and ozone and involves 23 jurisdictions. Although the States made significant progress through the OTAG process, they were unable to reach a final resolution on the emission reductions necessary or the schedule to achieve reductions to address upwind emissions. Thus, it would not be reasonable for EPA to leave open the issue of implementation in light of the need for downwind areas to rely on these reductions in order to demonstrate attainment by their attainment dates. See also the discussion in Section II.A.

Furthermore, EPA believes that requiring implementation of the SIP-required upwind controls, and thereby mandating those upwind reductions, by no later than May 1, 2003, is consistent with the purpose and structure of title I of the CAA. Under both section 172(a)(2), which establishes attainment dates for areas designated nonattainment for the 8-hour standard, and section 181(a), which establishes attainment dates for nonattainment areas for the 1-hour standard, areas are required to attain ''as expeditiously as practicable'' but no later than the statutorily-prescribed (for section 181(a)) or EPA-prescribed (for section 172(a)(2)) attainment dates. The implementation date of May 1, 2003 fits with both the more general requirement for areas to attain ''as expeditiously as practicable'' and the latest attainment dates that apply for purposes of the 1-hour standard and that EPA will establish for the 8-hour standard.

The overarching requirement for attainment is that areas attain ''as expeditiously as practicable.'' This requirement was established in the CAA in the 1970 Amendments and has been carried through in both the 1977 and 1990 Amendments. Thus, although Congress has provided outside attainment dates under the 1970, 1977, and 1990 Amendments, States have always been required to attain as expeditiously as practicable. Congress has furthered this concept of ensuring that emission reductions are achieved on an expeditious, yet practicable, schedule through its inclusion of other provisions in the CAA that rely on similar concepts. Most notably, under both subpart 1 and subpart 2 of part D of title I of the CAA, areas are required to make reasonable further progress toward attainment and thus are not allowed to delay implementation of all measures until the attainment year.[63] While the ROP requirements directly apply only to emission reductions that designated nonattainment areas need to achieve to address local violations of the standard, these provisions highlight congressional intent that—at a minimum—reasonably available or practicable measures should not be delayed if such measures are needed to attain the standard by the applicable attainment date. Thus, it is consistent for EPA to require upwind areas to adopt practicable control measures on a schedule that will help to ensure timely attainment of the standard in downwind areas.

In addition, the May 1, 2003 implementation date is consistent with the statutorily-prescribed ''outside'' 1- hour attainment dates for many of the areas that will benefit from the SIP call reductions.

Currently, areas designated nonattainment for the 1-hour standard have attainment dates ranging from 1996 to 2010. For those with attainment dates in the years 1996–1999, EPA is analyzing whether such areas should receive an attainment date extension due to transported emissions or whether such areas should be reclassified, or ''bumped up,'' under section 181(b)(2), to the next higher classification and therefore be subject to additional control requirements and a later attainment

[63] CAA sections 171(1) and 172(c)(2) (requiring that nonattainment area SIPs provide for reductions in emissions that may reasonably be required by the Administrator for the purpose of ensuring attainment of the applicable national ambient air quality standard by the applicable date; 182(b)(1) and (c)(2)(B) (requiring, respectively, 15 percent reductions between 1990 and 1996 and additional 3 percent average reductions per year until the attainment date, unless, among other things, the plan includes ''all measures that can be feasibly implemented in the area, in light of technological achievability'').

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date.[64] To the extent that an attainment date extension is appropriate, consistent with the general requirement of the CAA, it should be no later than the date by which the necessary reductions can practicably be achieved. Thus, it is appropriate for EPA to require upwind reductions by May 1, 2003—a date that EPA has determined can be practicably achieved—in order to allow these areas to attain as expeditiously as practicable. Additionally, there are areas with attainment dates of 2005[65] and 2007[66] that will benefit from the reductions upwind States will require in response to the SIP call. The May 1, 2003 compliance date is sensible in light of the requirement for these areas to make reasonable further progress toward attainment under section 182(c)(2)(B) and to attain as expeditiously as practicable but no later than 2005 or 2007.

The implementation date of May 1, 2003 is also consistent with the attainment date scheme for the 8-hour ozone NAAQS. The EPA is required to promulgate designations for areas under the 8-hour ozone NAAQS by July 2000. Pub. L. No. 105–178 section 6103 and CAA section 107(d)(1). In draft guidance EPA made available for comment in August 1998, the EPA indicated that most new areas that violate the 8-hour ozone NAAQS (but not the 1-hour ozone NAAQS) can achieve sufficient emissions reductions to produce one ozone season's clean air quality by the end of 2003 if EPA establishes May 1, 2003 as the compliance date for this rule.[67] The EPA suggested that these areas would also be eligible for an ozone transitional classification, provided they submit a SIP by 2000 (see the August 1998 proposed guidance). Therefore, in the proposed guidance, EPA has indicated that when the Agency reviews and approves ozone transitional area SIPs, the Agency anticipates establishing December 31, 2003 as the attainment date, for planning purposes, for almost all of the transitional areas. The EPA believes that establishing December 31, 2003 as the attainment date for these areas is consistent with the requirement of CAA section 172(a)(2)(A) that ''the attainment date for an area designated nonattainment with respect to a [NAAQS] shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date of designation.'' The EPA interprets this requirement to mandate that controls, either in the downwind nonattainment area or in upwind areas, should be implemented as expeditiously as practicable, when doing so would accelerate the date of attainment. For the reasons described elsewhere, the EPA believes it is practicable for States to implement the controls mandated under today's rulemaking by May 1, 2003, and that doing so would ensure that areas subject to the 8-hour NAAQS will attain the standard as expeditiously as practicable. Doing so will be consistent with the requirement that downwind nonattainment areas make reasonable further progress toward attainment.

B. Budget Achievement Date

In the NPR, the EPA stated that although it would mandate the full implementation of the required SIP controls by an earlier date, it would require the affected States to demonstrate that they will achieve their NO_X budgets as of the year 2007. The NPR explained that the 2007 date would allow EPA to make use of the substantial technical information collected by OTAG. The OTAG had selected the year 2007, had collected inventory data geared towards this date, and had generated air quality modeling information geared towards this date. The NPR further stated that the EPA had doubts that there would be significant differences in amounts of emissions and impact on ambient air quality between an earlier date and 2007, in light of the fact that during this period, emissions would generally increase somewhat as a result of growth in activities that generate emissions, but would also decrease due to continued application of federally mandated controls.

The EPA continues to believe that 2007 is an appropriate target date for the affected States to use in demonstrating whether their SIP will achieve the required emissions reductions, generally for the same reasons as expressed in the NPR. Based on the 2007 projections, States are expected to achieve their statewide emissions budgets (based on the required emissions reductions achieved by May 1, 2003) by September 30, 2007 which is the end of the ozone season.

Throughout this rulemaking process, the EPA has relied on technical data generated by OTAG geared towards the 2007 date, and it would be an ill-advised use of resources if EPA did not incorporate the emissions inventories and modeling results generated by the multi-stakeholder OTAG process, and instead developed comparable information for an earlier date. Such an effort would be time consuming and resource intensive. Furthermore, no State is disadvantaged by the requirement to demonstrate compliance with the budget later than the requirement to implement SIP controls because States may count both the growth in emissions and the reductions in emissions from Federal measures that would occur in the interim. Finally, the year 2007 is the latest attainment date under the 1-hour NAAQS for areas in States affected by today's rulemaking, i.e., the severe-17 areas of including Chicago, Milwaukee, and New York, so that this date is a sensible target date for affected States to use in projecting whether they will achieve the required emissions reductions.

VI. SIP Criteria and Emissions Reporting Requirements

A. SIP Criteria

The NPR and SNPR discussed SIP revision approval criteria and the schedule for States' submission plans for meeting statewide emission budgets in response to this SIP call under section 110(a)(2)(D). The EPA received a number of comments related to the proposed SIP approval criteria. This section summarizes these comments on key issues and presents EPA responses.

1. Schedule for SIP Revision

In the NPR, EPA proposed that each State must submit a demonstration that it will meet its assigned Statewide emission budget (including adopted rules needed to meet the emission budget) by September 30, 1999.[68] The EPA received numerous comments concerning this proposed timeframe.

Comments: The EPA received many comments on the practicality of allowing States 12 months to submit SIPs in response to this rulemaking. Some commenters articulated that some States anticipate administrative obstacles that could create problems in

[64] See Guidance on Extension of Attainment Dates for Downwind Transport Areas, Memorandum from Richard Wilson, dated July 17, 1998.

[65] Severe-15 areas, such as Baltimore and Philadelphia, as well as any Serious areas that do not receive an attainment date extension and are bumped up due to a failure to attain, will need to attain no later than 2005.

[66] Severe-17 areas, such as New York City, Philadelphia, Chicago and Milwaukee, need to attain the standard no later than 2007.

[67] ''Proposed Implementation Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS) and the Regional Haze Program,'' John S. Seitz, Director, Office of Air Quality Planning and Standards, to Regional Office Air Division Directors, August 18, 1998. The guidance has been made available for 30-days public comment through a Federal Register Notice of Availability (63 FR 45060, August 24, 1998). The date of the notice is the official start date for the comment period.

[68] In the NPR, EPA proposed the SIP submittal date to be within 12 months of the date of final promulgation of this rulemaking. Promulgation means signature so long as the rulemaking is made available to the public on the same day.

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submitting their SIP revisions by 1999. On the other hand, many commenters expressed concern about extending the SIP submittal deadline to 18 months based on the additional adverse impact that NO_X emissions from upwind areas would have on downwind air quality if the schedule for reductions were extended. Arguing that the States would have ample time to formulate an approvable SIP, these commenters supported a 12-month SIP submission date.

Response: After considering these comments, EPA is requiring that SIP revisions be submitted within 12 months after the date of signature of this final rule. This date is appropriate in light of the fact that States which are subject to today's rulemaking will need to achieve reductions in NO_X emissions by May 1, 2003. Requiring States to submit SIP revisions within the 12-month timeframe will ensure that controls necessary to reduce these emissions will be in place on time.

The Agency believes the health risks associated with ozone pollution require the NO_X SIP call to proceed expeditiously. Delaying the SIP submission date by an additional 6 months would hinder downwind areas' efforts to improve air quality in a timely manner.

Twelve months is adequate time to submit a NO_X reduction SIP. States were involved in the OTAG for 2 years and, during that time, developed lists of feasible NO_X control strategies and compiled information about control strategy costs. This groundwork will assist States in making decisions about their NO_X reduction strategies and should expedite the SIP submittal process. Further, States developed NO_X emission inventories for modeling purposes during the OTAG process. The States, therefore, have the information for the source categories on which to focus. As a result, many elements needed for putting together a NO_X reduction strategy have already moved forward.

Since OTAG concluded in June 1997, the States have had time for internal review of data, and refinement of their emission inventories. This SIP call rulemaking provides EPA's view of a reasonable cost-effective strategy to reduce NO_X in the 23 jurisdictions. The EPA's action provides a good starting point for State NO_X reduction strategies; States can embrace the Agency's approach or use it as a basis for tailoring their own programs. If States elect to participate in EPA's model trading rule, the SIP process will be further simplified because States can adopt the entire package of recommended strategies.

Therefore, under section 110(k)(5) for the 1-hour NAAQS and section 110(a)(1) for the 8-hour NAAQS, a demonstration that each State will meet the assigned Statewide emission budget (including adopted rules needed to meet the emission budget) must be submitted to EPA in its SIP revision.

2. Approvability Criteria

In the NPR, EPA described the elements listed below that States must include in their ozone transport SIP revisions (62 FR 60365).

The EPA proposed that the approvability criteria for transport SIP submissions appear in 40 CFR 51.121. Most of the criteria are substantially identical to those that already apply to attainment SIPs, for example, a description of control measures that the State intends to use.

The SNPR proposed additional SIP approvability criteria for control strategies that will help States meet their NO_X budgets (63 FR 25912–25914). The legal authority for these additional approvability criteria was articulated in the SNPR (63 FR 25913, footnote 5). The EPA received numerous comments related to these additional criteria.

a. Source Categories Subject to Additional Approvability Criteria. In the SNPR, EPA proposed that, if a State should choose to meet this SIP call by regulating NO_X sources (boilers, turbines and combined cycle units) serving electric generators with a nameplate capacity greater than 25 MWe and boilers with a maximum design heat input greater than 250 mmBtu/hr, the State would need to frame these control measures and monitoring requirements as either: (1) Mass emissions limits, (2) emissions rates assuming maximum utilization, or (3) an alternative approach, as described more fully in the next subsection. The EPA solicited comment on the reasonableness of extending these approvability criteria to additional NO_X sources. The EPA explained that the ability to comply with a mass emissions limit using reasonably available technology and to accurately and consistently monitor mass emissions were key factors for coverage by the additional approval criteria.

In the SNPR (63 FR 25923), EPA also outlined criteria for sources to participate in the NO_X Budget Trading Program. The EPA explained that the ability to accurately and consistently monitor NO_X mass emissions was a key factor for participation in the trading program. The EPA proposed that the trading program include the same sources listed above as well as other large steam-producing units (units above 250 mmBtu/hr) which would include combustion turbines or combined cycle systems, as well as boilers that do not serve electrical generators.

The EPA now believes that the SIP approvability criteria should cover all NO_X sources serving electric generators with a nameplate capacity greater than 25 Mwe and all boilers, combustion turbines and combined cycle units with a maximum design heat input greater than 250 mmBtu/hr. The Agency believes this group is appropriate because of the considerations set forth in the SNPR. For example, all of these sources can comply with a mass emissions limit using reasonably available technology and can accurately and consistently monitor mass emissions. In addition, EPA believes that mass emissions limits remain highly cost-effective for these sources, even when future growth is accommodated within the limits. Based on the analyses in the RIA, EPA projects that even if actual growth for this group of sources exceeds EPA's projected growth by over one-third, mass emission limits would remain highly cost-effective according to the criteria used for this rule. Therefore, in this final rule, EPA is requiring that the additional SIP approvability criteria outlined below apply to States that select regulatory requirements covering boilers, turbines and combined cycle units that are greater than 250 mmBtu/hr—regardless of whether they are connected to an electrical generator of any size—or to boilers, turbines and combined cycle units that serve electrical generators greater than 25 Mwe, regardless of the heat input capacity of the unit.

b. Pollution Abatement Requirements. The EPA proposed requiring States that choose to meet their budget through control requirements for such large NO_X sources to express the requirements in one of three ways: (1) In terms of mass emissions, which would limit total emissions from a source or group of sources; (2) in terms of emissions rates that when multiplied by the affected source's maximum operating capacity would meet the tonnage component of the emissions budget for this source or for these sources; or (3) an alternative approach for expressing regulatory requirements, provided the State demonstrates to EPA that its alternative provides assurance equivalent to or greater than option (1) or (2) that seasonal emissions budgets will be attained and maintained.

Comments: Seven commenters generally support the approach of

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expressing regulatory requirements as mass emissions limitations. One of these commenters does not object to a mass limit provided that the limit covers a time period no shorter than the ozone season, and that sources should be allowed to maintain flexibility within the ozone season. Several commenters generally support a rate-based limit, one of which noted that EPA's own rule-effectiveness studies show that rate-based limits can be very effective. Another commenter opposes the use of mass emission limits and urges EPA not to require monitoring procedures and data generation that are inconsistent with current requirements under the Acid Rain Program (namely the use of an emissions rate limit). Other commenters believe that States, not EPA, should decide the form of the limit. Finally, one commenter recommends both a cap on mass emissions and an emissions rate limitation.

Response: As explained in the SNPR (63 FR 25912), EPA believes that regulatory requirements in the form of a maximum level of mass emissions for a source or group of sources have the greatest likelihood of achieving and maintaining the Statewide NO_X emissions budget. As with the entire SIP call, the new approvability criteria are designed to apply to total emissions throughout the ozone season and are not intended to apply to shorter time periods within the ozone season. This, however, does not limit a State's ability to require emissions limitations for a shorter time period if deemed necessary in a specific ozone attainment plan.

Although several commenters supported using rate-based limits, they did not provide evidence to refute EPA's belief that the proposed criteria would provide superior environmental results over rate-based limits alone. The EPA maintains that the proposed criteria provide the greatest assurance to downwind States that the air emissions from upwind States will be effectively managed over time. Regarding EPA's rule effectiveness studies, they do confirm that rate-based limits can be effective in achieving a specific emissions rate. However, the studies do not address the emissions variations that may take place at the regulated sources due to changes in utilization under rate-based limits, including the potential for significant increases, particularly in light of utility restructuring. Under the proposed criteria, mass emissions from the regulated sources would stay within a fixed tonnage amount despite shifts in utilization of the sources. Finally, EPA does not believe that the rate-based NO_X emissions limits prescribed under title IV of the CAA are relevant to this rulemaking. Since the time of the 1990 CAA amendments, EPA, States, local governments, and the regulated community have all gained considerable experience with regulatory requirements expressed in terms of mass emissions limitations which demonstrates their feasibility and high degree of effectiveness. For these reasons and the reasons described in the SNPR, EPA is including these additional SIP approvability criteria in today's action.

c. Monitoring Requirements. The Agency proposed requiring these large combustion NO_X sources to use continuous emissions monitoring systems (CEMS), and requested comment on requiring the use of the NO_X mass monitoring provisions in 40 CFR part 75 to demonstrate compliance with applicable emissions control requirements.

Comments: Some commenters generally support the use of CEMS for large combustion sources. One commenter noted that while the preamble and the proposed revisions to part 51 would require CEMS on all sources, the requirements set forth in subpart H of part 75 allow for non-CEMS monitoring options for units that are infrequently operated or that have low mass emissions of NO_X.

Response: The EPA believes that programs like the Acid Rain Program and RECLAIM have shown that CEMS can be effectively used on boilers, turbines and combined cycle units to demonstrate compliance with a mass emissions limitation. The Agency also believes that, while CEMS provide more consistent and accurate data, allowing non-CEMS monitoring options for low-emitting or infrequently operated units greatly increases the cost effectiveness of these requirements without significantly jeopardizing the quality of the data used to ensure compliance with the requirements of the SIP call. Therefore, EPA agrees with the commenter that the part 75 provisions allowing non-CEMS monitoring options for low-emitting or infrequently operated units are reasonable. The EPA is requiring the use of the NO_X mass monitoring provisions in 40 CFR part 75 in the final SIP approval criteria.

d. Approvability of Trading Program. In the SNPR, EPA expressed its intent to approve the portion of any State's SIP submission that adopts the model rule, provided: (1) The State has the legal authority to adopt the model rule and implement its responsibilities under the model rule, and (2) the SIP submission accurately reflects the NO_X emissions reductions to be expected from the State's adoption of the model rule (63 FR 25913). The EPA also stated that a State could develop State regulations in accordance with the model rule. In Section VII.C.3 of this preamble, the Agency clarifies the extent to which a State's regulations may deviate from the model rule and still receive streamlined approval. Regulations providing for streamlined approval appear in paragraph (p) of 40 CFR 51.121.

3. Sanctions

In the preamble to the proposed rule, EPA explained the mandatory sanctions process that is established in section 179(a) and (b) of the CAA (62 FR 60368). This process is triggered upon a finding by EPA that a State failed to submit a SIP in response to a SIP call. One sanction—either increased offsets for new or modified major stationary sources or restrictions on highway funding—is imposed 18 months after the finding is made and the second sanction 6 months later. The EPA requested comment on the order in which these two sanctions should be imposed in response to the SIP call. The EPA further requested comment on whether EPA should use its discretion under section 110(m) to expand the geographic scope of the highway funding sanction.

Comment: One commenter specifically commented on the order in which the two sanctions should be imposed. The commenter recommended that the offset sanctions apply first—18 months after the finding—and the restrictions on highway funding apply second—6 months after the offset sanction.

Response: This is the approach that EPA took in its final rule addressing the sequence of mandatory sanctions for State failures to respond to submittals required under part D of title I of the CAA. For the reasons stated in the preamble to that final rule (59 FR 39832), EPA is providing in the final SIP call rule that the offset sanction will apply 18 months after EPA makes a finding and the restrictions on highway funding will apply 6 months after the offset sanction applies.

Comments: Several commenters generally commented that EPA should be fair and equitable in making findings and imposing sanctions. Other commenters suggested that to be fair and equitable—and because the sanctions are an important backstop to ensuring emission reduction are achieved—EPA should apply the same or similar sanctions to upwind attainment areas as to nonattainment areas that do not comply with the SIP call. Recognizing that the highway

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sanction can apply to attainment areas only under section 110(m), one commenter encouraged EPA to develop a mandatory clock for the imposition of discretionary sanctions. Finally, one commenter stated that the nature and timing of sanctions should reflect a State's particular circumstances; however, this commenter also emphasized the need for parties to know the impact of sanctions ahead of time so that they can effectively react.

Response: The EPA agrees that sanctions are an important backstop and plans to make timely findings where States fail to submit or submit an incomplete or disapprovable SIP in response to the SIP call. The EPA agrees that areas should be treated fairly and plans to ensure that areas with similar circumstances are not treated differently in making findings of failure to submit and incompleteness. However, at this time, EPA is not prepared to determine whether and when it is appropriate to use the discretion provided under section 110(m) in imposing sanctions. The EPA believes it is not appropriate to make a general determination regarding the application of sanctions under section 110(m); rather if circumstances warrant the use of sanctions under section 110(m), EPA may take future rulemaking action to use that authority. Before EPA uses the section 110(m) authority, EPA must go through notice-and-comment rulemaking, which should provide States adequate certainty about EPA's intentions on the use of discretionary sanctions and time to respond to any action that EPA may take.

Comment: One commenter suggested that the timeframes for the imposition of sanctions are too short and will undermine States' efforts to comply with the SIP call. In addition, the commenter states that the imposition of sanctions serves no useful purpose in light of EPA's intent to promulgate a FIP.

Response: The EPA did not propose imposing sanctions more expeditiously than the timeframes mandated by the CAA. If EPA makes a finding of failure to submit or incompleteness shortly after the SIP is due, the State will have 18 months in which to make a submission that EPA determines is complete before the first sanction would be imposed. Thus, the statute provides sufficient additional time for the State to correct the problem before any sanction would apply. Under the statute, sanctions apply independently of EPA's obligation to promulgate a FIP. Congress recognized that the most efficient and effective programs are those operated by the State; thus, the CAA provides for the continued imposition of sanctions as a means to encourage States to adopt a program to replace the FIP.

Comment: One commenter opposes restrictions on highway funding imposed by any highway sanction in nonattainment areas and especially Statewide.

Response: Under section 179(a) and (b), the highway funding sanction is one of two sanctions that must be imposed due to a continuing failure of a State to adopt a SIP program, including a SIP in response to a SIP call. Under section 179(b), the highway funding sanction can only apply in a nonattainment area. However, under the discretionary sanctions provision in section 110(m), EPA may impose the highway funding Statewide. (See 59 FR 1476, 1479–80 for a more detailed discussion.) The EPA would undertake notice-and-comment rulemaking before imposing sanctions beyond the nonattainment area pursuant to section 110(m).

Comments: Finally, several commenters recommended that EPA not sanction serious areas for failing to demonstrate attainment by 1999 where those areas are affected by transported emissions that will not be controlled until after the 1999 attainment date.

Response: The EPA is not addressing in this rulemaking the process for imposing sanctions for areas that fail to submit or submit incomplete or unapprovable attainment demonstrations. The EPA recently issued a policy memorandum explaining how it anticipates addressing transport for serious areas through rulemaking actions on submitted attainment demonstrations. See memorandum from Richard D. Wilson, EPA Acting Assistant Administrator, to EPA Regional Administrators, dated July 16, 1998, ''Extension of Attainment Dates for Downwind Transport Areas.''

In the preamble to the proposed rule, EPA indicated that if an area fails to implement an approved SIP, the Agency can make a finding that triggers the sanctions clock but does not trigger an obligation to promulgate a FIP. Compare sections 179(a)(1) and 110(c)(1). One commenter noted that EPA should take a forceful role in assuring implementation. Implementation of control measures to achieve the reductions required under the NO_X SIP call is crucial in moving all areas to attainment of the ozone standards. The EPA intends to make findings of failure to implement where the circumstances warrant such a finding.

4. FIPs

Comment: The EPA received several comments supporting the approach outlined in the NPR in which EPA would propose a FIP at the same time as taking final action on the SIP call. The comments noted that the FIPs may be necessary to enforce the SIP call budgets and to assure fair treatment of complying States and industry as compared to States that are not responsive to the SIP call. In addition, many comments were submitted urging EPA to delay proposal of FIPs until (1) after the States have had time to respond to the SIP call, (2) the need for the FIP is established, or (3) up to 2 years after the final SIP call.

Response: Also signed today is a separate notice titled ''Federal Implementation Plans to Reduce the Regional Transport of Ozone,'' EPA is proposing FIPs for each of the jurisdictions affected by the final SIP call rulemaking. While EPA will have a non-discretionary duty to promulgate a FIP within 2 years of a finding that a State has failed to submit a complete SIP, EPA agrees with certain commenters that the timing of the FIP proposal should allow for promulgation in time to require NO_X emissions reductions by sources at about the same time in States that comply with the SIP call and States that do not. Under a delayed FIP proposal approach, sources in the non-complying States might experience an unfair competitive advantage over sources in States which elected to reduce their NO_X emissions and reduce interstate transport of ozone and ozone precursors in an earlier timeframe, consistent with the SIP call rulemaking. More importantly, delaying the FIP proposal would potentially delay reductions of ozone pollution and NO_X emissions in any non-complying State which would unnecessarily jeopardize attainment and public health and welfare. Therefore, proposing a FIP today will ensure that EPA can promulgate a FIP very shortly after the time the SIPs are due, in the event of any State's failure to comply with today's final rule.

B. Emissions Reporting Requirements for States

As stated in the November 7, 1997 NPR and the May 11, 1998 SNPR, the EPA believes it is essential that compliance with the regional control strategy be verified. Tracking emissions is the principal mechanism to ensure compliance with the SIP call and to assure the downwind affected States

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and EPA that the ozone transport problem is being mitigated.[69]

1. Use of Inventory Data

If tracking and periodic reports indicate that a State is not implementing all of its NO_X control measures beginning on May 1, 2003 or is off track to meet its required reductions by September 30, 2007, EPA will work with the State to determine the reasons for noncompliance and what course of remedial action is needed. The EPA will expect the State to submit a plan showing what steps it will take to correct the problems. Noncompliance with the NO_X transport SIP call may lead EPA to make a finding of failure to implement the SIP and potentially to implement sanctions, if the State does not take corrective action within a specified time period.

The EPA will use 2007 data to assess how each State's SIP actually performed in meeting the statewide NO_X emissions budget.

2. Response to Comments

The EPA proposed reporting requirements in the May 11, 1998 SNPR. That proposal elicited several comments during the public comment period. Some of these comments resulted in changes to the final reporting requirements.

Comment: One commenter asked that the EPA review the need for triennial collection of annual (i.e for the full year) emissions data for uncontrolled sources, as compared to collection of only ozone season data for uncontrolled sources.

Response: The EPA has reviewed the need for reporting of full year emissions (as opposed to only ozone season emissions), and has revised the final rule to remove a requirement that full year emissions be reported. In the final rule, only ozone season emissions must be reported in the annual, triennial and 2007 reports. This NO_X SIP call is aimed at controlling transport of emissions during the ozone season and reporting of full year emission for the purposes of this SIP call is not necessary.

Comment: One commenter said that EPA should evaluate the reporting burden to entities other than the 22 States and the District of Columbia. These entities are likely to include owners/operators of facilities that will be required to report emissions data to States as part of this information collection. Another commenter said EPA should address the additional resource burden on States and facilities required to report.

[69] Legal authority for the reporting requirements was articulated in the supplemental notice of proposed rulemaking (63 FR 25915–6).

Response: Since the emissions reporting rule does not place requirements directly on any sources but only on the 23 jurisdictions which receive the SIP call, the EPA is under no legal obligation to evaluate the indirect burdens on sources that may result from the promulgation of this rule. However, based on EPA's assumed control strategy, EPA has performed an analysis of costs which could be incurred by facilities if States require facilities analyzed in EPA's assumed control strategy to report information to aid States in complying with the rule. This cost information includes both capital costs for monitoring equipment, such as continuous emission monitors, and labor costs for testing. These costs are included in the RIA for this rule which is located in the docket for the rulemaking (docket no. A–96–56).

Comment: One commenter is concerned that the definition of point and area sources does not coincide with the definition of smaller point sources included in the inventory, nor with the definition of major sources in ozone nonattainment areas where the threshold is either 25 or 50 tons per year. Another commenter stated that the definition of ''point source'' should reach at least down to the 50 ton per year level, if not lower. This commenter also said that, for consistency, EPA should have a single definition of ''point source'' for the purpose of this rule.

Response: All sources with NO_X emissions equal to or greater than 100 tons per year will remain point sources. However, the EPA has revised its definition of point source for this final rule's reporting requirements to allow States the option of specifying a smaller threshold than 100 tons/year of NO_X for defining point source. When a State chooses this option, non-mobile sources smaller than the State-defined threshold would be area sources in that State. This allows States to tailor their definition of point source to maintain consistency with their own current requirements.

In the proposal, the EPA specifically solicited comments on whether the State reporting time for source emissions should be shortened to no later than 6 or 9 months after the end of the calendar year for which the data are collected. This would allow corrective actions, if needed, to be taken prior to the next ozone season. The EPA also solicited comments on whether different reporting schedules should be established for the different source categories, so that the data which can be obtained more readily would be submitted sooner. The EPA has received several comments on these topics, suggesting a variety of reporting times.

Comment: A State recommended that since the performance of electric generating facilities is known promptly, EPA should shorten the reporting time to no later than 4 to 6 months after the end of the ozone season for which the data are collected. The comment did not specify whether this reporting period , which is shorter than the proposed 12 months, would apply only to electric generating facilities or should apply to all NO_X emitting sources. Another State said the point source emissions reporting period can be shortened to 9 months. Other commenters favored a 12 month or more reporting period. Several commenters did not believe that 12 months after the end of the calendar year is a reasonable time to submit reports and suggested periods ranging from 18 to 24 months. Some commenters thought the reporting time for area and mobile sources must be longer than for point sources; one commenter thought the reporting time for all source types should be uniform.

Response: Many of the emissions from large electric generating facilities would be reported directly to EPA more rapidly than 12 months, if States elect to adopt the model trading program; however, the EPA continues to believe that 12 months from the end of the calendar year for which the data is collected is a reasonable time to require a State to report all emissions from all types of sources. This 12 month period is supported by the comments which say that 12 months, or even less in some situations, is a sufficient reporting time. The EPA believes that States can report emissions from area and mobile sources, as well as stationary sources, within the 12 month period. The uniform 12 month reporting period for all source types was chosen to simplify reporting requirements. However, a State has the option of collecting emissions from particular sectors more rapidly if it wishes. Therefore in the final rule, the EPA is requiring that States submit the required annual and triennial emissions inventory reports no later than 12 months after the end of the calendar year for which the data are collected. Because downwind nonattainment areas will be relying on the upwind NO_X reductions to assist them in reaching attainment by the required dates, EPA believes it is important that data be submitted as soon as practicable to verify that the necessary emissions reductions are being achieved. Early reports will allow States to more quickly respond to implementation problems detected by the reports. States should formally notify the appropriate EPA

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Regional Office when making the submittals.

3. Final Rule

After taking into account the comments submitted in response to the May 11, 1998 proposal, EPA today is promulgating emission inventory reporting requirements for States subject to the NO_X SIP call. The regulatory text appears in 40 CFR 51.122, and the main emission reporting requirements are summarized in Table VI–1 below.

TABLE VI–1.—SUMMARY OF NO_X REPORTING REQUIREMENTS

If you own or operate	and	then, your State must report to EPA the source's
A point source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season[2] emissions. 1. triennially [3,5]. 2. for 2007[5].
A point source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [4]. 2. triennially [5]. 3. for 2007 [5].
An area source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
An area source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.
A mobile source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
A mobile source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.

[1] The EPA considers the State to rely on regulations to achieve the NO_X reductions required if those regulations require reductions beyond those reflected in the base case 2007 inventory.
[2] Ozone season is May 1 through September 30.
[3] Triennial reporting (which is every 3 years) starts with emissions occurring in 2002.
[4] Annual reporting starts with emissions occurring in 2003.
[5] Triennial and 2007 reports for point sources contain additional data elements not required in the annual reports.
[6] The data elements in the annual report for area and mobile sources satisfy the reporting requirements for these source categories for the triennial and 2007 reports. However, the triennial reports start with emissions occurring in the year 2002 and the annual reports start with emissions occurring in the year 2003.

4. Data Elements to be Reported

In addition to reporting the NO_X emissions values shown in Table VI–1, the State must report other critical data necessary to generate and validate these values. This includes data used to identify source categories such as site name, location and (source classification code) SCC codes. It also includes data used to generate the NO_X emissions values such as fuel heat content and activity level. The specific data elements required for each source category are further defined in 40 CFR 51.122.

5. 2007 Report

The EPA is requiring that States submit to EPA for the year 2007 a special onetime statewide NO_X emissions inventory from all NO_X sources (point, area, and mobile) within the State. The data reporting requirements are identical to the reporting requirements for the triennial inventories, and this reporting requirement is being imposed to allow evaluation of whether the budget is met in 2007. This one-time special inventory is necessary because the ordinary 3-year reporting cycle does not fall in the year 2007.

States which must submit the 2007 inventory may project incremental changes in emissions from 2007 to 2008 to allow the 2008 inventory requirement to be more easily met and to reduce the burden on States which must submit full NO_X inventories for consecutive years, i.e., 2007 and 2008.

The EPA received comments saying that EPA should not require the special report in 2007 due to increased resources required but rather should adjust the schedule of the triennial reports so that a triennial report year will fall on 2007. Alternatively, the EPA could eliminate the 2008 triennial report. The EPA has considered these alternatives, but believes that the schedule which was proposed is necessary to maintain consistency with

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other EPA reporting requirements and is not unnecessarily burdensome.

6. Ozone Season Reporting

The EPA is requiring that the States provide ozone-season (i.e., May 1 through September 30) inventories for the sources for which the State reports annual, triennial and 2007 emissions. The ozone season emissions may be calculated from annual data by prorating emissions from the ozone season by utilization factors that must be reported and that are further defined in 40 CFR 51.122. For the triennial and 2007 reports, ozone season emissions from all NO_X source categories within the State, controlled or uncontrolled, must be reported. The EPA is requiring that each State provide its ozone season calculation method to EPA for approval.

7. Data Reporting Procedures

When submitting a formal NO_X budget emissions report and associated data, the State should formally notify the appropriate EPA Regional Office of its activities. States are required to report emissions data in an electronic format to one of the locations given below. Several options are available for data reporting. The State may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.) A second option is for the State to convert its emissions data into the Emission Inventory Improvement Program/ Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network, or can be placed on a file transfer protocol (FTP) site. As a third option, the State may submit its emissions data in a proprietary format based on the EIIP data model. For the last two options, the terms ''submitting'' and ''reporting'' data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying that group that the data are available in the specified format and at a specific electronic location (e.g., FTP site). A fourth option for annual reporting (not for third year reports) is to have sources submit the data directly to EPA. This option will be available to any source in a State that is both participating in an approved trading program and that has agreed to submit data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

For the latest information on data reporting procedures, call the EPA Info Chief help desk at (919) 541–5285 or e-mail to info.chief@epamail.epa.gov.

8. Confidential Data

Emissions data being requested in today's action are not considered confidential by the EPA (See 42 U.S.C. 7414). However, some States may restrict the release of certain types of data, such as process throughput data. Where Federal and State requirements are inconsistent, the EPA Regional Office should be consulted for final reconciliation.

C. Timeline

The reporting requirements fit into the general time line summarized below:

September 30, 1999—Deadline for SIP submissions in response to this SIP call.

2002—The first triennial emissions inventory report must be submitted for ozone season emissions for this year. States must collect emissions inventory information for all NO_X sources in the State. This report must be submitted by December 31, 2003 (i.e., 12 months after the end of the calendar year for which the data are collected.)

May 1, 2003—The SIP measures required to achieve the NO_X reductions must be implemented by this date.

2003—The first annual emissions inventory report must be submitted for certain ozone season NO_X emissions for this year. Specifically, States must collect emissions information regarding all sources for which the State is relying on measures to meet its NO_X budget (''SIP call sources''). This report is due December 31, 2004.

2004—The second annual emissions inventory report must be submitted for ozone season emissions from SIP call sources for this year. This report is due December 31, 2005.

2005—The second triennial report must be submitted for ozone season emissions from all NO_X sources for this year. The report is due December 31, 2006.

2006—The third annual report must be submitted for ozone season emissions from SIP call sources in the State for this year. This report is due December 31, 2007.

2007—The special year 2007 emission inventory report for ozone season emissions from all NO_X sources in the State must be submitted for this year. This report is due December 31, 2008. The EPA will assess whether States have met their budgets in the year 2007.

2008—The third triennial emissions inventory report must be submitted for ozone season emissions for this year. This report is due December 31, 2009.

Annual and triennial reports must continue to be submitted in future years beyond 2008 in order for the EPA to track compliance with the budget or any revisions to the budget that may occur after 2007.

VII. NO_X Budget Trading Program

A. General Background

In the November 7, 1997 proposed rulemaking, EPA offered to develop and administer a multi-state NO_X trading program to assist States in the achievement of their budgets. Today's notice sets forth a model program on which States may choose to base their SIP submittal. The trading program employs a cap on total emissions in order to ensure that emissions reductions under the transport rulemaking are achieved and maintained, while providing the cost effectiveness of a market-based system. States can voluntarily choose to participate in the NO_X Budget Trading Program by adopting the final model rule, which is a fully approvable control strategy for achieving over 90 percent of the emissions reductions required under the transport rulemaking.

B. NO_X Budget Trading Program Rulemaking Overview

Prior to publication of the proposed NO_X Budget Trading Program, EPA held two public workshops to solicit comments and suggestions from States and other stakeholders on a NO_X cap- and-trade program. Over 150 people participated in each of the workshops. To facilitate meaningful comments from these participants, EPA developed papers on critical issues that were made available for review prior to each workshop. These papers discussed major issues relevant to developing a NO_X Budget Trading Rule, delineated options and, in some cases, offered recommendations. The issues associated with each working paper were presented at the workshops, followed by open discussion periods allowing workshop participants to comment and discuss each issue. Input from workshop participants was extremely helpful in drafting the proposed NO_X Budget Trading Program. In addition to

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input gained from the workshop process, the NO_X Budget Trading Program builds directly upon the Ozone Transport Commission's NO_X Budget Program and recommendations from the OTAG's Trading and Incentives Workgroup. On May 11, 1998, EPA published the proposed NO_X Budget Trading Program as a part of the supplemental notice for the proposed ozone transport rulemaking. The final NO_X Budget Trading Rule published in today's notice reflects changes that have been made in response to comments received on the May 11, 1998 proposal.

C. General Design of NO_X Budget Trading Program

1. Appropriateness of Trading Program

The EPA proposed that a voluntary market-based program be established as one possible means for a State to meet its NO_X emissions reduction obligations under the NO_X SIP call. The vast majority of commenters, including States, industry, and environmental groups, supported a market approach over traditional ''command and control'' mechanisms to fulfill reduction requirements. However, many commenters argued that the proposed State budgets, based on the cost-effectiveness of an emission limit of 0.15 lb/mmBtu for large combustion sources, are too stringent to provide sufficient surplus allowances to support a market. These commenters argued that cost and technological constraints would prevent regulated sources from over-controlling, thus reducing the pool of allowances and the cost savings EPA predicts would accompany trading. However, several other commenters stated that the trading program was the most cost-effective means to reduce emissions and would in fact generate sufficient allowances for trading. These commenters noted that all but the highest emitting coal-fired units can achieve this rate, and that many sources are able to achieve emission limits significantly below 0.15 lb/mmBtu. They also argued that, at least in the early years of the trading program, the growth factors used to determine the budgets will lead to a less stringent emission reduction requirement than 0.15 lb/mmBtu.

The EPA notes that nothing requires a State to impose a 0.15 lb/mmBtu limit on its large combustion sources. The States will select in their SIPs which sources to regulate and the type of regulation to impose in order to achieve their NO_X budgets. The EPA believes that trading for large combustion sources under a budget based on 0.15 lb/mmBtu is a feasible, highly cost-effective means of meeting a State's budget. The Agency believes that 0.15 lb/mmBtu can easily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_X levels below 0.15 lb/mmBtu and should therefore easily be able to generate excess allowances if trading is allowed. The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/mmBtu emission limit, selective catalytic reduction (SCR) will generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/mmBtu by installing SCR, it can provide excess allowance to another coal-fired boiler and obviate the need for that boiler to install SCR. (For further technical justification for the feasibility of 0.15 lb/mmBtu, see Section III.B.2 of this preamble.) In summary, EPA concludes that, should a State elect to control large combustion sources with a budget based on an emission rate of 0.15 lb/mmBtu, ample allowances would exist to sustain a market under the NO_X Budget Trading Program.

Several of the commenters who did not support the trading program proposed by EPA were generally wary of the use of market approaches for environmental regulation, especially in the context of ozone attainment strategies, citing concerns that emissions in existing nonattainment areas may increase under such a program. The EPA, however, believes that a trading program is an appropriate mechanism to achieve the NO_X reductions required under the SIP call. The EPA proposed the trading program in the SNPR based on recommendations from OTAG, experience from the Ozone Transport Commission, and EPA's public workshops held in November and December 1997. This trading program was designed to mitigate transport of ozone and its precursors to facilitate attainment and maintenance of the ozone NAAQS. Analyses in conjunction with the SIP call show that implementation of a trading program with a uniform control level results in no significant changes in the location of emissions reductions than would result from a non-trading scenario (''Supplemental Ozone Transport Rulemaking Regulatory Analysis'', April 1998, page 2–19). The NO_X reductions required by the SIP call will significantly lower background levels of ozone and can be coupled with local measures to achieve further NO_X reductions, as well as VOC reductions, where necessary to reach attainment. States concerned with contribution by local sources in the trading program are free to limit emissions from particular sources by imposing source-specific emission limits where deemed necessary.

2. Alternative Market Mechanisms

The SNPR proposed to establish a model cap-and-trade program for certain large combustion sources. This proposed program employs a cap on total emissions to ensure achievement and maintenance of the emissions reductions required under the NO_X SIP call while providing the flexibility and cost effectiveness of a market-based system. Several commenters supported EPA's recommendation for a cap-and- trade program. Several others complained that EPA's focus on a capped trading program was inappropriate, citing OTAG's recognition that NO_X market systems could also be implemented without an emissions cap. As a result, these commenters felt that EPA could not make a cap a prerequisite to approval of a State trading program. They suggested that EPA recognize that a rate-based program can be part of a viable SIP, perhaps by outlining parameters of an acceptable alternative program or working with OTAG States to develop a rate-based program that would better accommodate future growth. Another issue raised by a few commenters was that the trading program would either conflict with or would ignore existing local or State-based trading programs.

The EPA first reiterates that the model program is voluntary (63 FR 25918). In providing a cap-and-trade program as a streamlined means by which to comply with the NO_X SIP call, EPA does not preclude implementation of other solutions. The purpose of the trading program is to provide a compliance mechanism that capitalizes on a proven means of cost effectively meeting a specific emissions budget that the Agency will assist States in administering.

As OTAG concluded, the procedures for a cap-and-trade program have already been developed and used successfully, whereas procedures for other types of multi-state trading programs have not been developed and implemented to the same degree. Therefore, EPA does not have the same level of experience or established protocols to follow in the design and administration of other types of trading programs. The OTAG did encourage development of provisions to implement other types of trading programs, and EPA recognizes that these alternative trading programs may be appropriate in some circumstances.

However, EPA recommends a cap-and-trade program for purposes of the NO_X SIP call because, by limiting total NO_X emissions to the level determined to address the interstate transport problem, a cap better ensures achievement and maintenance of the environmental goal articulated in the NO_X SIP call. In contrast, under a non-cap trading program, the addition of new sources to the regulated sector or increased utilization of existing sources could increase total emissions above the level determined to address transport, even though a NO_X rate limit is met.

States, however, have the flexibility to respond as they see fit to meet their emissions budgets established under the NO_X SIP call. States are free to pursue other regulatory mechanisms or include other types of trading programs in their SIPs, whether newly created or already existing, on the condition that they meet EPA's SIP approval criteria as delineated for the NO_X SIP call. These criteria mandate that regulatory requirements for boilers, turbines and combined cycle units that are greater than 250 mmBtu or that serve electrical generators that are greater than 25 MWe be expressed in one of three ways: (1) In terms of mass emissions; (2) in terms of emissions rates that when multiplied by the affected sources' maximum operating capacity would meet the tonnage component of the emissions budget for these sources; or (3) an alternative approach for expressing regulatory requirements, provided the State demonstrates, to EPA's satisfaction, that its alternative provides equivalent or greater assurance than options (1) or (2) that seasonal emissions budgets will be attained and maintained. For further information regarding SIP approvability criteria, see Section VI.A.2.b of this preamble.

3. State Adoption of Model Rule In the SNPR, EPA proposed that States electing to participate in the NO_X Budget Trading Program could either adopt the model rule by reference or develop State regulations in accordance with the model rule. The few commenters on this issue were primarily concerned about lack of guidance by EPA in this area for State adoption of the model rule and the potential for deviation from the model rule in the State-adopted rules. This section clarifies EPA's intent in issuing a model rule and distinguishes between sections of the model rule that State rules must mirror, and those that States may choose to alter or eliminate while maintaining a SIP that is approvable for purposes of joining the NO_X Budget Trading Program.

a. Process for Adoption. One commenter suggested that rather than adopting the NO_X Budget Trading Program, it should be sufficient for each State to include a statement in its SIP declaring that the State will participate in the Federal program, along with a demonstration of the authority for the State to do so. This would leave the details in the Federal rule and avoid differences that could arise through each State adopting its own rule. However, EPA does not have the statutory authority under title I to promulgate a Federal cap-and-trade program to achieve a State's SIP call budget unless the State fails to respond adequately to the SIP call. The EPA understands the commenter's concern regarding differences among State rules to implement the NO_X Budget Trading Program, and intends to ensure consistency as explained in the following Section.

The EPA's intent in issuing a model rule for the NO_X Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving more than 90 percent of the required reductions under the NO_X SIP call. States choosing to participate in the program will be responsible for adopting State regulations to support the NO_X Budget Trading Program, and submitting those rules as part of the SIP. As articulated in the proposed rulemaking (63 FR 25920), there are two legal alternatives for a State to use in joining the NO_X Budget Trading Program: incorporate 40 CFR part 96 by reference into the State's regulations, or adopt State regulations that mirror 40 CFR part 96 but for the variations and omissions described below.

b. Model Rule Variations. The EPA would like to clarify the variations and omissions from the model rule that are acceptable in a State rule, to provide States flexibility while still ensuring the environmental results and administrative feasibility of the program. More specifically, EPA will clarify those variations that maintain a State's eligibility for the streamlined SIP approval associated with adoption of the model rule, those changes that will require more extensive review by EPA prior to approval, and those changes that are not acceptable for incorporation into the NO_X Budget Trading Program.

In order for a SIP revision to be approved for State participation in the NO_X Budget Trading Program, on a streamlined basis or otherwise, the State rule should not deviate from the model rule except in the areas of applicability, NO_X allowance allocation methodology, and early reduction credit methodology (all of which are described briefly in the following paragraphs and in more detail in subsequent Sections of today's notice). Deviations from the model rule regarding allocation methodologies and early reduction credit methodologies as defined in this Section do not impact a State's eligibility for streamlined approval of its SIP with respect to the NO_X Budget Trading Program. However, some deviations regarding applicability will require more extensive EPA review, as explained below. Changes to program applicability may render a State's rule ineligible for streamlined approval, though the rule would still be eligible for approval after a more thorough EPA review.

State rules that deviate beyond the applicability, allocation, and early reduction credit flexibility provided in the model rule would not be approvable for inclusion in the NO_X Budget Trading Program. SIPs incorporating a trading program that is not approved for inclusion in the broader NO_X Budget Trading Program may still be acceptable for purposes of achieving some or all of a State's obligations under the NO_X SIP call, provided the SIP criteria outlined in Section VI.A.2.b are met. However, only States participating in the NO_X Budget Trading Program would be included in EPA's tracking systems for NO_X emissions and allowances used to administer the multi-state trading program.

For States participating in the NO_X Budget Trading Program, applicability is one of the three main areas in which the State may deviate from the model rule. State rules need to include an applicability section that at least covers the core sources defined in the model rule, but States may allow additional stationary sources to participate in the trading program. These sources must be able to monitor and report emissions in accordance with the model rule, and identify an individual responsible for fulfilling program requirements to be eligible for inclusion. States have three options to expand applicability and one to limit it, as explained in the following paragraphs.

States may choose to expand applicability either by: (1) Including smaller sources in the core source categories, (2) including additional source categories, or (3) providing individual sources the ability to opt in. Expansion of applicability to smaller core sources will maintain the State's eligibility for streamlined SIP approval with regard to the NO_X Budget Trading Program. Including additional source categories beyond the core sources (e.g., municipal waste combustors), however, will require more careful review by EPA

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in some cases to ensure that the trading program requirements can be met, and therefore preclude streamlined SIP approval otherwise associated with adoption of the model rule. Regarding individual source opt-ins, States have the discretion to determine whether or not to include this provision in their State rule. The opt-in provision is not a prerequisite to approval of a SIP incorporating the NO_X Budget Trading Program. However, if a State does choose to include provisions for opt-in sources, these provisions must mirror those in the model rule. Providing the provisions do so, the SIP remains eligible for streamlined EPA approval.

States may also choose to limit applicability of the trading program by allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per control period) to be exempt from trading program requirements. A State may include this exemption provision as it appears in the model rule to allow these sources not to participate in the trading program, or a State may omit the provision. Neither of these actions will interfere with streamlined SIP approval by EPA, provided the exemption provisions mirror the model rule if included in the State rule.

In terms of allocations, States must include an allocation section in their rule, conform to the timing requirements for submission of allocations to EPA that are described in this preamble, and allocate an amount of allowances that does not exceed their State trading program budget. However, States may allocate NO_X allowances to NO_X budget sources according to whatever methodology they choose. The EPA has included an optional allocation methodology in 40 CFR part 96, but States are free to allocate as they see fit within the bounds specified above, and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

Today's final rule also includes an optional methodology in § 96.55(c) that States may use for issuing early reduction credits from the State compliance supplement pools. However, States may distribute the State compliance supplement pool to sources as they wish in accordance with the requirements set forth in 40 CFR 51.121(e)(3) and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

In summary, a State is eligible for streamlined approval of the portion of their SIP incorporating the NO_X Budget Trading Program if the State adopts all the provisions of the model rule (e.g., banking and monitoring provisions) with variations incorporated only in the manner explained in this Section. Streamlined approval requires that applicability extends only to the core sources, or to core sources and smaller sources within the core source categories and that the opt-in provision and the exemption option for sources with a low federally permitted emission limit, if included, mirror those in the model rule. Regarding allocations, eligibility for streamlined approval extends to those State rules whose allocations do not exceed the State trading program budget and are determined in accordance with the timing requirements delineated in the model rule. A State rule is still eligible for approval, but not streamlined approval, if the applicability determination for the NO_X Budget Trading Program extends beyond the core sources to additional source categories, to allow for the additional review necessary to ensure such an extension of applicability is administratively feasible and environmentally sound. A State rule is also eligible for streamlined approval if it includes methodologies for issuing credit from the State compliance supplement pool in accordance with the provisions in 40 CFR 51.121(e)(3). Differences among States in these areas will provide flexibility while not detracting from the operation or implementation of the multi-state trading program. Therefore, variations as explained in this section are acceptable to EPA with assurance that State rules will be sufficiently consistent. In addition, joint implementation of the program with EPA will ensure that once these consistent rules are established, they will be implemented consistently as well.

Several commenters expressed concern that the lack of prohibitions on State-imposed trading restrictions in conjunction with the model rule would lead to variation between States and cripple the trading program. The EPA agrees with commenters that additional restrictions imposed on the trading program by individual States could increase economic costs without providing significant environmental benefit. Therefore, EPA does not believe that any restrictions on trading are necessary, and does not foresee approving State rules that include trading restrictions in SIPs incorporating the NO_X Budget Trading Program. However, to address local air quality problems, a State participating in the NO_X Budget Trading Program may establish permit limitations for specific sources participating in the trading program. The EPA considers such a limitation appropriate given local air quality concerns and does not consider it a trading restriction, and therefore the incorporation of such limitations will not preclude streamlined SIP approval. These sources would still participate in the NO_X Budget Trading Program and the unconstrained market operating in the program, but could not use allowances to exceed their permit limitation; the source would be held to the permitted limit, regardless of how many allowances it holds for the purposes of the trading program. This topic is discussed in more detail in the next Section.

4. Unrestricted Trading Market

a. Geographic Issues. For the NO_X SIP call, EPA is basing the State budgets on the uniform application of reasonable, cost-effective NO_X control measures for each State determined to contribute significantly to nonattainment in a downwind State. The EPA's analyses show that the collective reductions across the region will produce significant air quality benefits across the region. The development of and justification for the State budgets under the NO_X SIP call is described in Section III, Determination of Budgets. Although the analyses in today's final action demonstrate that the collective emissions for the NO_X SIP call region significantly contribute to nonattainment, the location of particular emissions does impact the effects that the emissions have on other areas within the region. Emissions in some locations may cause greater overall effects than emissions from other locations.

In the SNPR, EPA proposed a single trading program allowing all emissions to be traded on a one-for-one basis without restrictions on trading allowances within the SIP call region. The EPA also solicited comment on whether the trading program should attempt to factor in differential effects of NO_X emissions based on the location of the emissions. Possible options for factoring in the differential effects include defining exchange ratios for trades between areas based on the differential effects of emissions between areas, establishing subregions for trading, and/or prohibiting certain trades (63 FR 25902 at 25919).

The Agency received more than fifty comments on this issue from the regulated community, States, and environmental organizations. A number of commenters did support limiting trading by establishing smaller subregions within the SIP call region or establishing trading ratios based on the idea that there are differential effects of NO_X emissions based on the location of the emissions. However, none of these commenters included a complete proposal with a justification or description for the appropriate subregional boundaries or trading ratios. The majority of commenters on this subject favored unrestricted trading within areas having a uniform level of control. Most commenters supporting unrestricted trading stated that restrictions would result in fewer cost-savings without achieving any additional environmental benefit and would increase the administrative burden of implementing the program. They expressed concern that discounts or other adjustments or restrictions would unnecessarily complicate the trading program, and therefore reduce its effectiveness.

Consistent with the proposal, the final model rule is designed to be a single jurisdiction trading program allowing all emissions to be traded on a one-for-one basis, without restrictions or limitations on trading allowances within the trading area. EPA has used the IPM to evaluate the emissions and cost impacts of alternative regulatory options under the SIP call for the electric power sector. These analyses can be found in the RIA. The model has been used to show the level and location of emissions if the SIP call were implemented under a number of different alternatives including unrestricted trading and command-and-control approaches. The results indicate that significant shifts in the location of emissions reductions would not occur with unrestricted trading compared to where the reductions would occur under command-and-control and intrastate only trading scenarios. Based upon the IPM results and EPA's air quality modeling, EPA has chosen a region-wide trading program allowing all emissions to be traded on a one-for-one basis without trading restrictions. EPA's analyses suggest that the net effect of all the trades is that the net emissions will not significantly shift within the region compared to a command-and-control scenario. For this reason, EPA believes that the need for trading subregions or trading ratios that differ from one-for-one are unsubstantiated for the purposes of this SIP call and the NO_X Budget Trading Program.

Although the location of net emissions is not expected to significantly shift as a result of trading, it is possible that a State may identify a specific location (e.g., major NO_X source adjacent to or within an urban center) where NO_X reductions would be particularly beneficial for ozone mitigation. For these situations, a State may establish a specific permit limitation restricting the amount of NO_X that may be emitted from the source. The source would still be included in the trading program but it would not be allowed to emit above the amount specified in the permit limitation regardless of the number of NO_X allowances it may hold. The source would be allowed to trade the allowances it is unable to use. In this way, States will be able to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program.

b. Episodic Issues. The EPA also received several comments addressing the episodic nature of ozone formation and whether this should be factored into the design of the trading program. Commenters noted that under the NO_X SIP call, which is designed to reduce total NO_X emissions from May through September of each year, it is still possible that NO_X emissions may be relatively higher during ozone episodes compared with NO_X emissions on other days between May and September. In addition, the effect of a unit of emissions may be higher during ozone episodes. To address this concern, the commenters stated that the trading program should provide incentives or safeguards to ensure that NO_X emissions reductions are achieved specifically during ozone episodes. One commenter asserted that emissions could either be capped during ozone episodes or that the trading program could place a premium on the use of NO_X allowances during ozone episodes. The commenter recommended the latter option. The premium would require that sources surrender NO_X allowances at rates greater than 1-to-1 for each ton of NO_X emitted during the ozone episodes.

Consistent with the NO_X SIP call, the NO_X Budget Trading Program focuses on reducing total NO_X emissions from May to September for the jurisdictions that are identified in the NO_X SIP call and that choose to participate in the trading program. Proposals to address NO_X emissions during specific episodes and in specific nonattainment areas are more closely tied to issues affecting individual attainment plans rather than the goal of the NO_X SIP call which is to reduce transport. It would be very difficult to apply the appropriate premium to the individual sources that contribute NO_X emissions affecting specific ozone episodes. The meteorology and source contribution for each ozone episode is different. And in some cases, NO_X emissions and the resulting ozone may be transported for several days before contributing to an ozone violation.

Provisions designed to ensure that NO_X emissions reductions are achieved specifically during ozone episodes are more likely to be effective in controlling NO_X emissions that are released adjacent to or within locations frequently affected with elevated ozone levels. Where a State identifies such a source, EPA believes specific permit limitations are an appropriate and effective method for controlling the source's emissions. As stated in the previous section, EPA believes that States may use permit limitations to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program. Furthermore, this provides each State more flexibility in establishing its attainment plan rather than applying one approach to address the episodic nature of ozone throughout the SIP call region. Therefore, EPA has not included additional trading restrictions to address ozone episodes in the design of the final NO_X Budget Trading Program.

D. Applicability

1. Core Sources

In the SNPR, EPA proposed that compliance with the emission limitation requirements of the NO_X Budget Trading Rule, i.e., the requirement to hold sufficient NO_X allowances to cover emissions, apply to a core group of large stationary sources that includes all fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems (i.e., units) that serve an electrical generator of capacity greater than 25 MWe and to any fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems not serving a generator that have a heat input capacity greater than 250 mmBtu/hr. A unit was considered fossil fuel-fired if fossil fuels accounted for more than 50 percent of the unit's heat input on an annual basis. The EPA solicited comment on the appropriateness of the categories included in the core group, whether the size cut-offs should be higher or lower for the source categories, and the appropriateness of including other source categories in the core group. Comments on the concept of a core group fell into three broad categories:

- Those who agreed with the core group concept and who generally agreed with EPA's proposed core group definition;

- Those who felt that the core group definition was too limiting; and
- Those who felt that the core group definition was too inclusive.

a. Commenters Who Felt the Core Group Should Not Be Changed. Commenters who supported the concept of a core group generally and the cut-offs proposed by EPA specifically explained that the cut-offs are consistent with the Acid Rain Program and that the use of a core group will minimize inconsistencies that could impede establishment of interstate trading. Commenters also added that the program should provide the flexibility to allow additional sources to opt-in on an individual basis or for States to bring in additional sources on a categorical basis. Some of these commenters added that the timing for bringing in these sources or source categories should be dependent upon the ability of the source or source category to accurately monitor emissions. For some source categories it might be appropriate to bring them in at the start of the program; for others, it might be necessary to wait until their ability to quantify emissions has improved.

Commenters who generally supported the concept of a core group of sources as it was defined in the SNPR did have several specific concerns. One commenter noted that while the SNPR preamble clearly explained that the rule only included fossil-fuel-fired units, the rule itself was not clear on this issue. Another commenter suggested that because the proposed definition differentiated between electrical generating units and non-electrical generating units it excluded sources that should be in the trading program such as cogeneration facilities that consisted of boilers greater than 250 mmBtu/hr that served electric generating units with a rating of less than 25 MWe.

The EPA agrees that the establishment of a core group will help facilitate interstate trading as well as compliance with the emissions budget. If there is not some minimum group of trading participants, sources that are in the program will have less of an opportunity to trade allowances and realize the economic benefits of trading. In addition, by ensuring that most of the emissions from industries covered by the trading program are included in a capped system, the trading program can be simplified because concerns about load shifting to uncapped sources is minimized. The EPA also agrees that making the cut-offs consistent with existing regulatory programs helps to minimize conflicts with existing regulatory programs. The EPA also agrees with both of the concerns raised by the commenters. Therefore the regulatory definition of unit has been clarified to make it clear that a unit must be fossil-fuel fired. The EPA has also added a clarification to the definition of fossil-fuel fired. This clarification is intended to define a baseline period for determining if a unit is fossil-fuel fired. The revised definition states that fossil-fuel fired means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel comprises more than 50 percent of the annual heat input on a Btu basis. An existing unit is considered fossil-fuel fired if it meets this criterion for any year since 1990 (or if not operating since 1990 during the last year of operation). A new unit is considered fossil-fuel fired if it is projected to meet this criterion or, if after operation begins, it does meet this criterion.

In addition, to address the concern about excluding cogeneration facilities that are greater than 250 mmBtu/hr that serve electric generating units with a rating of less than 25 MWe, the applicability has been changed to include all units greater than 250 mmBtu/hr, regardless of how much electricity they generate.

b. Commenters Who Felt the Core Group Should Be Expanded. Commenters who felt the trading program should be expanded focused on a number of areas. Several commenters argued generally that the program should allow any source to participate if the source can document that emissions reductions have been achieved. A number of commenters mentioned as examples the inclusion of medium-sized and smaller stationary sources in the RECLAIM program. A few commenters argued that the addition of certain sources is needed for consistency with the OTC NO_X Budget Rule. Other commenters opposed the core group concept because they believe that regulation of low-level and local sources in the Northeast is an essential step in solving the ozone problem. Others argued that excluding non-utility sources from the trading program unfairly excludes these sources from least-cost compliance options. Some commenters suggested specific categories of units that should be allowed to, but not required to, participate in the trading program. These included:

(1) Municipal waste combustors;
(2) Internal combustion engines;
(3) Process units;
(4) Units for which the output product is not comparable to other units on which the allocations are based, such as process heaters, hazardous waste incinerators, process vents and nitric acid plants.

The EPA believes that many of the concerns about the core source definition stem from a misunderstanding of its purpose. The core sources definition was intended to indicate the minimum applicability requirements that a State rule would have to include to participate in a larger multi-state program that EPA would help to administer. It was not intended to limit individual States from including more sources (as long as the sources meet certain criteria further explained below) in the larger multi-state program (63 FR 25924). Nor was it intended to prohibit a State (or group of States) from developing its own trading program with a more limited applicability.

If, however, a State or group of States developed a trading program that did not meet the minimum requirements set forth in the model NO_X Budget Trading Program, such as minimum core source applicability, EPA would not participate in the administration of such a trading program. This is because it would not be administratively cost-efficient for EPA to manage multiple trading programs with a variety of applicability and other requirements designed to address the same issue.

The EPA is not expanding the core source group to include any additional sources because EPA believes that this decision is better left to the states. Therefore the model rule will allow a State to expand the applicability of the trading program to include additional stationary sources if the sources meet certain criteria. These criteria include the ability to accurately and consistently monitor and report emissions and the ability to identify a party responsible for ensuring that monitoring and reporting requirements are met, for authorizing allowance transfers and for ensuring compliance. The EPA's rationale for setting these minimum criteria are set forth in the preamble to the SNPR (63 FR 25923). Also, EPA addresses issues specifically related to the monitoring requirements for these sources in Section D.3 of today's preamble.

There are two mechanisms that can be used to include more sources in the program. One is for a State to expand the applicability criteria to include other source categories; the other is to give individual sources the ability to opt-in.

States that choose to expand the applicability criteria can do so (1) by lowering the applicability threshold for source categories that are already part of

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the core group in order to include smaller sources or (2) by including additional source categories that are not included in the core group. For instance a State in the OTC might choose to lower the applicability cut-off for electrical generating units to 15 MWe to make the program more consistent with the existing OTC NO_X Budget Program. If a State chose to expand the applicability criteria for source categories already included in the core group this would not affect EPA's streamlined approval of the NO_X Budget Trading program component of the State's SIP.

A State might choose to lower the applicability cut-off for sources in the core group to create different applicability cut-offs for new and existing units. This could help to better facilitate integration with a State's new source review program. The EPA took comment on this concept in the SNPR and received comments both for and against this proposal. Commenters who opposed it suggested that it would be a disincentive to replace old units with new cleaner units. Some of these commenters also noted that expanding the applicability cut-off for all units would provide an incentive to replace these older units. Commenters who favored it suggested that it would be an incentive to make new units as clean as possible. The EPA believes that it is appropriate for States to determine how best to handle the issue of small new units.

Another reason to allow smaller sources to opt-in is to simplify monitoring for situations in which a common stack is shared by a number of units, some of which are affected and some which are not. In this situation the owner or operator would have to either install monitors at each of the affected units, or install monitors at the common stack and at all of the non-affected units, so that the emissions from these units could be deducted from the emissions from the affected units. If the owner or operator is allowed to opt-in the nonaffected unit, they will be able to install one set of monitors at the common stack accounting for the emissions from all of the units.

If a State chose to include additional source categories, EPA would have to review the SIP submittal to ensure that those additional source categories met the minimum criteria for monitoring and reporting emissions and for having a responsible official. As further explained in the SNPR (63 FR 25924), EPA would also have to determine if it could successfully administer a regional trading program with the inclusion of these additional source categories.

In the SNPR, EPA proposed developing a list of specific additional source categories beyond the core group which a State could bring into the trading program without affecting EPA's streamlined approval of the trading component of the SIP. While this concept received general support, none of the commenters provided enough specific support to demonstrate that all of the sources in a given source category could meet the criteria to accurately and consistently monitor emissions. These comments are discussed in Section D.3.

The EPA believes that the opportunity for States to expand the applicability to include additional sources addresses concerns about incompatibility with the applicability requirements of existing programs, such as the OTC Trading Program, as well as concerns that an individual State might want to expand the program to address local ozone problems.

The other mechanism that can be used to broaden the applicability of the program is the individual opt-in procedures in subpart I of part 96. These provisions allow a source to opt-in, if it can meet the monitoring and reporting requirements of part 75. The EPA received a number of comments about the monitoring requirements of part 75 as they related to opt-ins. These comments are addressed in Section D.3 of today's preamble.

In the SNPR (62 FR 25940–25942 and 62 FR 25991–25994), EPA proposed that the individual opt-in provisions would only be applicable to fossil-fuel-fired, stationary boilers, combustion turbines, and combined cycle systems smaller than the applicability cut-offs of 25 MWe or 250 mmBtu/hr. The EPA agrees that the RECLAIM program has demonstrated that many combustion sources that are not included in the core applicability criteria can accurately and consistently monitor NO_X mass emissions using CEM (or other alternative protocols for units with low mass emissions) that are very similar to the provisions in subpart H of part 75. Therefore, in today's action EPA is allowing States to expand the opt-in provisions to include any stationary combustion source that emits to a stack and can meet the monitoring and reporting requirements of subpart H of part 75.

States that choose to add other combustion sources that are not part of the core group would also have to address issues related to allocating allowances for those types of sources. Allocation methodologies that may be appropriate for source categories covered in the core group may not be as applicable for other source categories. For instance, as one commenter noted, an output based allocation methodology might not make as much sense for a municipal waste combustor, since the primary purpose of a municipal waste combustor is to combust waste, not to generate usable output.

c. Commenters Who Felt the Core Group Is Overly Inclusive. A number of commenters argued that the burdens associated with including certain source categories would outweigh the benefits and that particular types of sources should therefore be excluded from the core group. Many of these commenters stated that individual sources in these groups should be allowed to opt in where there is a net economic benefit to them to participate rather than mandating inclusion of the source category. Specific categories include: non-utility boilers generally; generators of power for on-site use; combustion turbines exempt from Title IV; small cyclone boilers; combustion turbines below 100 MWe; small, particularly municipal, electric generating units (e.g., those under 25 MWe); and units with low potential to emit as defined by enforceable limits (e.g., peaking units with potential to emit less than 100 tons per year).

The EPA does not believe there is a great distinction between similarly sized utility and non-utility boilers. Both categories of boilers are similar in design, have similar control options and have similar control costs. Therefore, EPA is not excluding large non-utility boilers from the trading program. The EPA believes the same arguments that apply to utility and non-utility boilers also apply to generators of power for on- site use and generators of power for resale. In light of the fact that utility restructuring will provide more opportunities for generators of power for on-site use to resell the power they produce in the future, EPA believes that this distinction is even harder to make. Therefore, EPA is not excluding large generators of power for on-site use from the trading program.

In accordance with title IV of the CAA, the Acid Rain Program exempts simple combustion turbines that commenced commercial operation before November 15, 1990. These units were exempted from the Acid Rain Program because the SO_2 emissions from these units were extremely low. The NO_X emissions from these units are potentially higher; therefore, EPA is not adding a specific exemption for these types of units. However, many of these units are small and/or infrequently operated, so their actual NO_X emissions may be quite low; therefore, some of these units may qualify for the alternative compliance options for units with low NO_X mass emissions, explained below. Combustion turbines smaller than 100 MWe are also likely candidates to qualify for the alternative compliance option explained below.

The Acid Rain Program exempts cyclone boilers with a maximum continuous steam flow at 100 percent load of greater than 1060 thousand lb/ hr from NO_X control requirements under part 76. These units were exempted because one of the primary criteria in title IV of the CAA for setting emissions limitations under part 76 was comparability of cost with low NO_X emission controls on boilers categorized as group 1 boilers under Title IV (large tangentially fired and dry bottom, wall fired). There is no such criterion in the CAA applicable to this rulemaking. Also, since the emission reductions required by this rulemaking are more substantial than the emission reductions required under part 76 [70], the cost per ton of reducing NO_X emission reductions is correspondingly higher. Therefore, applicability cutoffs that were relevant in the part 76 rulemaking are not relevant in this rulemaking.

In response to the comment that small electrical generators less than 25 MWe should be exempt from the NO_X Budget Trading Program, they were proposed to be exempt and will be exempt under the final model rule. They do still have the option of opting into the program if they choose to do so.

In the SNPR (63 FR 25926), EPA took comment on allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per ozone season), that because of their size would be included in the trading program, to be exempt from the requirements of the trading program. In general commenters supported this concept. One commenter who supported the concept also added that it would be important to ensure that there were adequate requirements to assure that the individual sources who took advantage of this option demonstrated compliance with their unit-specific caps. The commenters who disagreed with this option expressed concern that a State's budget could be exceeded if emissions from these units were not accounted for.

Based on the comments received EPA continues to believe that it is appropriate to offer States the option of providing units that are above the applicability threshold but that have a very low potential to emit an alternative compliance option. This option would allow units that meet the requirements described below to be exempt from the requirements to hold allowances, and to comply with quarterly reporting requirements. In order to address the concern that sources must demonstrate compliance with their individual cap, EPA has added specific requirements that sources must meet in order to use this alternative compliance option.

Units that use this option would be required to:

(1) have a federally enforceable permit restricting ozone season emissions to less than 25 tons;

(2) keep on site records demonstrating that the conditions of the permit were met, including restrictions on operating time;

(3) report hours of operation during the ozone season to the permitting authority on an annual basis.

A unit choosing to use this compliance option would be required to determine the appropriate restrictions on its operating time by dividing 25 tons by the unit's maximum potential hourly NO_X mass emissions. The unit's maximum potential hourly NO_X mass emissions would be determined by multiplying the highest default emission rate for any fuel that the unit burned (using the default emission rates, in part 75.19 of this chapter) by the maximum rated hourly heat input of the unit (as defined in part 72 of this chapter).

States would be allowed, but not required, to incorporate this alternative compliance option into their SIPs. The EPA does agree that if a State does incorporate this option into the SIP, it would have to account for the emissions under its budget. Thus a State that chose to use this option would have to either:

(1) Subtract the total amount of potential emissions permitted to be emitted using this approach from the trading portion of the budget before the remaining portion of the trading budget is allocated to the trading participants;

or (2) Offset the difference between total amount of potential emissions permitted to be emitted using this approach and the 2007 base year inventory emissions for these same sources with additional reductions outside of the trading portion of the budget.

If States choose not to incorporate this alternative compliance option into their SIPs, or if they choose to incorporate it exactly as it is set forth in the model rule, it will not affect the streamlined approval of the trading rule portion of the SIP. A State may choose to require an alternative means of ensuring that the potential to emit for units utilizing the alternative means of compliance is limited to less than 25 tons, however if a State deviates from the model rule in this way, the SIP will no longer receive streamlined approval.

2. Mobile/Area Sources

The proposed rule did not include mobile or area sources in the trading program, but solicited comment on expanding applicability to include these sources, or to include credits generated by these sources, in the trading program. Mobile and area sources were not included in the proposed trading rule due to EPA's concerns related to ensuring that reductions were real, developing and implementing procedures for monitoring emissions, and identifying responsible parties for the implementation of the program and associated emissions reductions.

The EPA received comment from State and local government, industry and coalitions of industry, and environmental groups regarding the inclusion of mobile and area sources in the program. Comments focused on the following main areas: inclusion or exclusion of mobile and area sources, subcategories of mobile sources for inclusion, and the use of pilot programs to foster innovation.

Some commenters urged EPA to include mobile and area sources with as few restrictions as possible in the trading program, primarily on an opt-in or voluntary basis. These commenters argued that excluding mobile sources would reduce the potential scope and benefits of the trading by placing a large portion of States' NO_X inventory outside the scope of the trading program. They noted that the existence of RECLAIM protocols for mobile and area source credit generation demonstrated that EPA's quantification, verification, and administration concerns were misplaced.

The majority of commenters, however, indicated that mobile sources should not be included at this time and that the model rule should not be delayed to address concerns related to inclusion of these sources. Some commenters argued against ever including mobile and area sources in the program. One State argued that inclusion of mobile and area sources would destroy the integrity of the program since mobile and area source reductions are not necessarily real, verifiable and quantifiable, failing to display a level of certainty comparable to those sources included in the trading program. A few commenters indicated that mobile sources were inherently unsuited to a capped system, since the difficulties of measuring emissions from these sources precludes their inclusion in a budget.

[70] The lowest emission rate required under part 76 is 0.40 lbs/mmBtu.

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Several commenters suggested that some categories of mobile sources should be included while other categories should not. Commenters indicated, for example, that it is not feasible to have individual motorists participate in the cap-and-trade program due to the burdens and administrative complexity associated with such a vast number of sources and responsible parties in a trading system. Alternatively, commenters argued that manufacturers, fuel distributors, and fleet owners could be included if they were able to generate surplus emission reductions by going beyond the requirements established by some Federal measures. These commenters specifically cited the low-RVP regulations, the vehicle scrappage guidance, and the locomotive regulations as examples of such Federal measures.

Several commenters who recommended that mobile sources not be included in the program at this time also recommended that EPA sponsor pilot programs in States to study the feasibility of inter-sector trading and to develop mechanisms to address the specific concerns mentioned regarding the inclusion of mobile and area sources. Along similar lines, one industry commenter stated that mobile sources may be appropriate candidates for participation in the trading program only if adequate emission reduction measurement protocols can be developed. Foreseeing this occurrence, some commenters felt that EPA should leave a placeholder in the rule or add a provision that would include mobile and area sources once the mechanisms to address the specific concerns of EPA and others have been developed.

The model trading program that EPA is finalizing today will not include mobile and area sources for the reasons outlined in the SNPR. The EPA concurs with the concerns raised by commenters against the inclusion of mobile and area sources, regarding program integrity, emissions monitoring, and accountability. Most of the proponents of including mobile or area sources listed general reasons for including them such as increasing market efficiency, lowering costs, or simply the existence of RECLAIM protocols to do so. However, these commenters did not provide sufficient information or documentation to support the validity of these assertions, and several acknowledged that the potential for improvement in market efficiency or lower compliance costs was difficult to ascertain. Further, one proponent acknowledged that the RECLAIM protocols are new and not yet extensively utilized.

In fact, a recent audit of the RECLAIM program indicates that the volume of mobile source credits used under the program is very small (only 99 NO_X tons have been converted from mobile source reductions in the last five years). Only 5 requests for conversion of mobile source emission reduction credits to RECLAIM trading credits were approved in 1994, and no further requests had been received as of May 1998. The small amount of credits relative to the significant resource expenditure for the conversion of mobile source credits under the RECLAIM program (i.e., the need for case-by-case review given the variability and complexity of the petitions) suggests that the RECLAIM mobile source protocols and strategy are not yet a cost-effective option for the trading program.

The EPA remains willing to consider adding mobile or area sources to the trading program in the future. Most commenters recommended that the program be opened to mobile or area sources once adequate mechanisms are developed for addressing related concerns. In response to these comments, and those recommending that EPA support pilot programs in States in order to facilitate resolution of the areas of concern for mobile and area sources, EPA will investigate how grant funding may be used for such pilots. Additionally, EPA is pursuing possible ways to incorporate mobile and area source strategies into other trading and incentive programs. Through these efforts, EPA will work with States in finding solutions to adequately address concerns such as emissions variability, difficulty in controlling emissions growth, difficulty in monitoring emissions levels, and difficulty in establishing emissions baselines. Through this process, EPA and States will explore and develop the necessary protocols that could eventually allow the inclusion of mobile and area sources in some capacity in the NO_X Budget Trading Program. Anticipating that the quantification, verification, and administration concerns regarding expansion of the trading program to include mobile and area sources may be sufficiently resolved in the future, EPA is reserving in this rulemaking a section in part 96 for future inclusion of mobile or area sources in the NO_X Budget Trading Program.

The EPA is aware of other concerns on which the Agency did not receive comment, including the adequacy of some of the existing mobile source protocols and the enforcement of mobile source credit generation strategies. These emerging issues, coupled with past experience, and the issues raised by commenters lead EPA to conclude that it is not appropriate to include mobile and area sources in the NO_X Budget Trading Program at this time.

3. Monitoring

For the reasons set forth in the SNPR (63 FR 25938–40), EPA proposed that sources in the NO_X Budget Trading Program use the monitoring methodologies in proposed subpart H of part 75 to quantify their NO_X mass emissions (63 FR 28032). The comments that EPA has received can be classified into three main categories:

- Support for requiring the use of part 75 to demonstrate compliance with the trading program,
- Support for using CEMS on large units, but concerns about using part 75 as the monitoring protocol, and
- Concerns about requiring CEMS.

Some of the commenters concerned about requiring CEMS focused on units of any size that are not subject to the provisions of the Acid Rain Program. Others focused on smaller units.

The EPA proposed revisions to part 75 (63 FR 28032) for a number of reasons, one of which was to add procedures for monitoring NO_X mass emissions (subpart H). These procedures could be used by sources to comply with any State or Federal program requiring measurement and reporting of NO_X mass emissions. In particular, subpart H would be used by sources to meet the monitoring and reporting requirements of the NO_X Budget Trading Rule (part 96) and the monitoring and reporting requirements of the SIP call for (1) combustion units (boilers, turbines and combined cycle units) which serve electric generators greater than 25 MWe and (2) combustion units greater than 250 mmBtu/hr, regardless of whether they serve a generator.

The part 75 revisions also proposed to make a number of other changes that would affect units using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass emissions program that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA, a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions, new quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75, and several minor technical changes to maintain uniformity within part 75 and to clarify various provisions.

The following discussion addresses comments received in the SNPR docket (A–96–56) that are related to the general requirement to monitor emissions, the requirement to monitor emissions using CEMS, and the requirement to monitor using part 75. Although EPA had requested that all comments related to the use of part 75 for monitoring NO_X mass be submitted to the part 75 docket (A–97–35), some comments also dealt with the specific requirements set forth in part 75.

In today's rulemaking, EPA is finalizing sections of part 75 related to monitoring NO_X mass emissions as well as those which address the excepted monitoring methodology for units with low mass emissions of NO_X and SO_2 that combust oil or natural gas. Units using this methodology to comply with the requirements of part 96 would be subject only to the NO_X mass emission requirements and not to the SO_2 mass emission requirements. For a more complete discussion of the NO_X mass monitoring and reporting provisions in part 75, see the Amendments to Part 75 Section below and Appendix A of this preamble. These Sections discuss both the comments received in the part 75 docket as well as the comments received in the SNPR docket that address the specific requirements of part 75.

a. Use of Part 75 to Ensure Compliance with the NO_X Budget Trading Program. Several commenters supported the idea of requiring all sources in the trading program to meet the monitoring provisions of part 75. Some of these commenters noted that part 75 provides the consistent and accurate monitoring requirements necessary to ensure the integrity of a cap and trade program. They also noted that the proposed revisions offered the flexibility needed for sources to be able to reasonably comply.

Several commenters supported the concept of trying to consolidate the monitoring and reporting requirements for units in the NO_X Budget Trading Program already subject to part 75 under the Acid Rain Program.

Response: The EPA agrees that accurate and consistent data are important to ensure the integrity of a trading program and that the protocols in part 75 provide for such accurate and consistent data from stationary combustion sources. Today's final model rule would require all sources in the trading program (including sources currently subject to part 75) to use the monitoring and reporting procedures set forth in subpart H of part 75.

b. Use of CEMS on Large Units. A number of commenters expressed support for the requirement that large units should use CEMS to quantify NO_X mass emissions. Many of these commenters did, however, have concerns about using part 75 as the basis for this monitoring. Some of these commenters elaborated that part 75 was specifically developed for utility units and that it might not be applicable to other types of units. Commenters also expressed concerns about costs associated with upgrading existing CEM systems to meet the part 75 requirements. The main alternatives they suggested were either using existing State monitoring and reporting requirements or allowing States the discretion to create or approve new monitoring and reporting requirements.

Response: For reasons set forth in the preamble to the SNPR, EPA believes that the use of CEMS, in general, and the protocols in part 75, more specifically, are the most effective way to ensure that NO_X mass emissions from large combustion sources are quantified in an accurate and consistent manner from source to source and are reported in a consistent and cost-efficient way. This is important to maintain the integrity and efficiency of the trading system.

The EPA believes that the protocols in part 75 can appropriately be applied to all of the core sources (fossil fuel-fired electric generating units and industrial boilers). The issues associated with monitoring NO_X mass emissions from a stack attached to a boiler, turbine, or combined cycle unit are the same regardless of whether that boiler, turbine, or combined cycle unit is owned or operated by a utility, by an independent power producer, or by a manufacturer. The EPA does acknowledge that there may be additional issues associated with monitoring NO_X mass from units such as process heaters or cement kilns.

The RECLAIM program uses very similar protocols to the ones in part 75 to quantify NO_X mass emissions. Both RECLAIM and part 75 require the use of NO_X CEMS and flow CEMS to quantify NO_X mass emissions from large sources combusting solid fuel. Both RECLAIM and part 75 also offer large oil and gas units an additional option for monitoring. This option involves the use of a fuel flowmeter and fuel sampling and analysis. The RECLAIM program requires monitoring of source categories that are in the NO_X Budget Trading Program core group, such as boilers and turbines, but also requires monitoring of source categories that are not in the core group, such as process heaters and cement kilns.

RECLAIM needed to establish a standing working group to resolve issues related to monitoring NO_X mass from such a wide range of source categories (See South Coast Air Quality Management District, RECLAIM Program Three Year Audit and Progress Report, May 8, 1998). EPA does not believe that the problems that RECLAIM has had with monitoring are related to the protocols that program uses. Rather, EPA believes these problems are due to the limited experience that both States and sources have with monitoring such a wide range of source categories.

The EPA believes that regardless of what protocols are used, if States opt to bring additional source categories into the trading program, issues related to monitoring at specific source categories will arise. These issues will need to be resolved, thus improving State and EPA experience with those source categories. If a State wants to include additional sources beyond those included in the core group, then EPA would resolve issues through the initial certification process for opt-in units. The EPA will also provide additional guidance on specific source categories, sharing the experiences gained with individual opt- in units.

Using one basic set of protocols will make it easier for states, sources and EPA to work together while gaining more experience with these sources and resolving the issues in a cooperative and consistent manner.

The EPA believes that the most significant costs associated with upgrading from an existing NO_X emission rate monitoring system to a part 75 NO_X mass monitoring system are associated with the need to monitor NO_X mass and would be incurred regardless of the specific monitoring protocol that was required. Many existing CEM rules other than part 75 require sources to monitor NO_X emission rate (in lbs/mmBtu) or NO_X concentration corrected for oxygen (in ppm)(e.g. monitoring requirements under Subpart D, Da, Db of part 60). In order to meet these requirements, a NO_X monitoring system must consist of a NO_X concentration CEM, a diluent CEM and a data acquisition and handling system (DAHS). The DAHS is the part of the system that collects raw monitor data, performs calculations, and generates reports.

In order to upgrade an existing system so that it can monitor NO_X mass, a source must install a flow CEMS, if it burns solid fuels, or must install either a flow CEMS or a fuel flow meter if it burns a homogeneous oil or gas. In addition, the source would have to

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upgrade its DAHS to reflect the reporting of NO_X mass rather than NO_X emission rate or NO_X concentration. These costs must be incurred, regardless of the protocol that a source used to monitor NO_X mass.

The EPA believes that a single monitoring and reporting protocol for the NO_X Budget Trading Program will keep the costs of upgrading systems to a minimum. This is because equipment vendors will be able to create standardized systems that will be applicable to all sources in the program, rather than having to create many different State- and source-specific systems. A single monitoring and reporting protocol will also help ensure a level playing field for all affected sources.

For these reasons, part 96 requires all large units to monitor NO_X mass emissions using CEMS in accordance with part 75. However, as explained below, part 75 does offer various monitoring options for low-emitting or infrequently operated oil- and gas-fired units, in addition to CEMS.

c. Commenters Who Do Not Believe That CEMS Are Necessary. Some commenters expressed concerns about requiring CEMS on any unit that does not currently have a CEMS monitoring requirement. Suggested alternatives included the use of stack test data and emission factors. Some commenters also suggested the testing and monitoring provisions of a source's title V permit.

Response: For large sources, EPA does not believe that stack test data and emission factors provide the consistent and accurate data needed to facilitate a trading program. Stack test data provide a one-time assessment of a source's emission rate. Emission factors at best are based on a series of stack tests at similar units. A unit's actual emission rate may fluctuate greatly over time due to factors such as the way the unit and/ or its associated control equipment is operated and maintained and the quality of fuel that the unit burns. An emission factor or stack test will often not be representative of that unit's actual normal emissions. Continuous monitoring of actual emissions will ensure that fluctuations in emission rates are accounted for. Because CEMS provide continuous monitoring, they can also indicate when emission control equipment is malfunctioning, thus, helping to ensure that the owners of units continue to properly operate and maintain any installed emission control equipment.

Title V permits incorporate all of the monitoring requirements to which a source is subject in order to demonstrate compliance with its current regulatory requirements. In addition, where a source is not subject to any other monitoring requirements, it sets forth minimum monitoring requirements. In many cases the current regulatory requirements do not require compliance with a mass emissions limitation. Therefore, the monitoring requirements are not designed to demonstrate compliance with a mass emission limitation.

Even when a source may have monitoring requirements designed to demonstrate compliance with a mass emissions limitation, the stringency of these requirements often varies from source to source and from State to State. These variations in turn lead to inconsistencies in sources' accounting of mass emissions. This both creates an uneven playing field for sources and undermines the integrity of the trading program.

The EPA believes that it is necessary for all sources in the trading program to be subject to accurate and consistent monitoring requirements designed to demonstrate compliance with a mass emission limitation. This will ensure compliance with the requirements of the SIP Call and will ensure the integrity of the trading program.

The EPA does believe that it is appropriate to provide lower cost monitoring options for units with low NO_X mass emissions. Part 75 allows non-CEMS alternatives to quantify NO_X mass emissions for gas and oil fired units that have low NO_X mass emissions and/or that operate infrequently.

In contrast, EPA does not believe that the types of protocols set forth in the Compliance Assurance Monitoring (CAM) rule, part 64, are appropriate for a trading program because they were not designed to quantify mass emissions. The preamble to the CAM rule further elaborates why these protocols are not appropriate for a trading program (62 FR 54915, 54916, 54922).

The EPA believes that the types of protocols in RECLAIM and the Ozone Transport Commission's NO_X Budget Trading Program (''OTC Program'') are more appropriate for a trading program because they were specifically designed to quantify NO_X mass emissions. The EPA also believes that the flexible monitoring options offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that burn solid fuels and all units that emit more than 10 tons per year, regardless of the type of fuel they burn.. The OTC Program requires CEMS on all units that burn solid fuels and all units that do not qualify as peaking units, that are larger than 250 mmBtu/hr or that serve generators greater than 25 MW. Like RECLAIM and the OTC Program, part 75 requires CEMS on all units that burn solid fuel. Part 75 also requires the use of CEMS on oil and gas fired units that emit more than 50 tons of NO_X annually (or for units that only report during the ozone season, 25 tons of NO_X during the ozone season), or that don't qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year.

The EPA believes that these exceptions in part 75 provide cost-effective monitoring alternatives to CEMs for small, low mass emitting, or infrequently used units, and therefore, it is appropriate that part 96 require all units to use part 75.

d. Issues Related to Monitoring and Reporting Needed to Support a Heat Input Allocation Methodology. For monitoring and reporting NO_X mass emissions, subpart H of part 75 requires the use a NO_X concentration CEM and a flow CEM. Since the methodology does not require the use of heat input, EPA would not require sources to monitor or report heat input or NO_X emission rate for a NO_X mass emission reduction program. If a State elects to use a periodically updating allocation methodology that utilizes heat input, it may need to require sources using this methodology to monitor and report heat input also.

e. Amendments to Part 75 (1) Summary of Part 75 Rulemaking. Title IV of the CAA requires the EPA to promulgate regulations for continuous emissions monitoring (CEM). On January 11, 1993, final rules (40 CFR part 75) were published (58 FR 3590). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746). A notice of direct final rulemaking and a notice of interim final rulemaking making further changes to the regulations were published on May 17, 1995 (60 FR 26510 and 60 FR 26560, respectively). Subsequently, on November 20, 1996, a final rule was published in response to public comments received on the direct final and interim rules (61 FR 59142).

The EPA proposed further revisions to part 75 on May 21, 1998 (63 FR 28032). These revisions included a new subpart H which sets forth procedures for monitoring NO_X mass emissions, which could be used by sources to comply with any State or Federal program requiring measurement of NO_X mass emissions, including the requirements

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of the NO_X Budget Trading Rule (part 96). The May 21, 1998 proposed revisions also proposed to make a number of other changes that would affect units that were using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass trading program under title I that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA; a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions; and new quality assurance requirements to fill in gaps identified by EPA during evaluation of the initial implementation of Part 75.

(2) Schedule For Part 75 Final Rulemaking. The comment period for the proposed revisions to part 75 ended on July 20, 1998. EPA anticipates completing rulemaking on all of proposed revisions to part 75 by the end of the year. However, because the revisions to subpart H of part 75 relating to the monitoring and reporting of NO_X mass emissions are integral requirements of the SIP Call, EPA is finalizing most of the requirements of subpart H of part 75 with today's action.

The EPA is also finalizing a new excepted monitoring methodology for units that combust natural gas and or fuel oil with low mass emissions of NO_X and SO_2. These provisions are being finalized because they are one of the methodologies that certain gas and oil units can use to quantify NO_X mass under the new subpart H of part 75.

The EPA is not finalizing the rest of the proposed revisions to Part 75 at this time because EPA is still evaluating the comments received on the proposed rulemaking. Many of these remaining provisions will be applicable to any unit that must use the requirements of part 75 in order to meet the requirements of title IV or to meet the requirements of a State or Federal NO_X reduction program that adopts the part 75 requirements. For example, the proposed revisions would allow a unit with CEMS to be exempt from the requirement to perform a linearity test in any quarter that the combustion unit for which the CEMs is installed operates for less than 168 hours. If EPA ultimately finalizes this proposed flexibility, it will become available both to units using part 75 to comply with title IV and to units using it to comply with the part 96 model trading rule. As another example, EPA proposed quality assurance requirements for moisture monitors that would be needed if pollutant concentration (NO_X, SO_2 or CO_2) were measured on a dry basis and needed to be converted to a wet basis so that mass emissions could be determined using a stack flow meter. If EPA ultimately finalizes this proposed requirement it will affect both units using part 75 to comply with title IV and units using it to comply with part 96 (or a State or Federal NO_X mass reduction program that adopts part 75).

The EPA is also not yet finalizing the recordkeeping and reporting requirements associated with either the NO_X mass monitoring provisions in subpart H or the low mass emitter monitoring methodology because EPA believes that these reporting requirements should be coordinated with any changes in the reporting requirements that result from the finalization of the rest of proposed revisions to part 75.

Therefore, EPA has closed the part 75 docket (A–97–35, with respect to the provisions that are being finalized in today's rulemaking: section 75.19, a new excepted methodology for estimating emissions for units with low mass emissions; and subpart H, a new subpart setting forth provisions for monitoring, recording and reporting NO_X mass emissions, except where EPA has reserved final action on related aspects of these provisions. EPA has not closed the docket with respect to the other provisions that were the subject of EPA's, May 21, 1998 proposal (63 FR 28032).

(3) *Summary of Major Differences Between Proposed and Final Revisions to Part 75.* The final rule contains two main differences to the NO_X mass monitoring and reporting provisions from what was proposed. The first is that a new methodology for calculating NO_X mass emissions is included. This methodology utilizes a NO_X concentration CEM and a flow CEM to calculate NO_X mass emissions. The second is that sources that are not subject to title IV are not required to monitor and report data outside of the ozone season unless otherwise required to do so by the Administrator or the permitting authority administering the NO_X mass trading program.

The final rule also contains two main differences from the proposal with regard to the new excepted monitoring methodology for low mass emitters. The first is that the methodology is applicable to units with calculated NO_X mass emissions of up to 50 tons, rather than 25 tons as proposed. The second is that in lieu of using default rates for NO_X set forth in the rule, the owner or operator of a unit using this methodology may instead elect to determine a unit specific rate by conducting stack testing. All of these changes are discussed in greater detail in Appendix A of this notice. At this time EPA is only addressing the comments dealing with the two main issues for which EPA is finalizing revisions to part 75, the reporting of NO_X Mass (subpart H) and a new excepted monitoring methodology for low emitters (§ 75.19). The EPA intends to address the rest of the comments on the part 75 rulemaking in a separate, future rulemaking. The discussions in Appendix A also address comments received in the SNPR docket (A–96–56) that related specifically to the monitoring requirements set forth in part 75.

E. Emission Limitations/ Allowance Allocations

Each State has the ultimate responsibility for determining the size of its trading program budget and its individual source allocations as long as the trading budget plus emissions from all other sources do not exceed the State's SIP Call budget. The proposed rule published on May 11, 1998 set timing requirements identifying when the allocations should be completed by each State and submitted to EPA for inclusion in the NO_X Allowance Tracking System (NATS) and provided an option specifying how a State might allocate NO_X allowances to the NO_X budget units. Today's final model rule clarifies the timing requirements for submission of allowance allocations to EPA and provides an optional allocation approach. Each State remains free to adopt the Model Rule's allocation approach or adopt an allocation scheme of its own provided it meets the specified timing requirements, requires new sources to hold allowances, and does not allocate more allowances than are available in the State trading budget.

1. Timing Requirements

In the SNPR, EPA set timing requirements identifying when a State would finalize NO_X allowance allocations for each control period in the NO_X Budget Trading Program and submit them to EPA for inclusion into the NATS. In developing the proposal, the Agency reasoned that uniform timing requirements would be important to ensure that all NO_X budget units in the trading program would have sufficient time and the same amount of time to plan for compliance for each control period, and sufficient time and the same amount of time to trade NO_X allowances. After considering a range of timing requirements, EPA proposed options that allocated NO_X allowances 5

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to 10 years in advance of the applicable control period. The proposal attempted to strike a balance between systems that change the allocations on an annual basis and systems that establish a single, permanent allocation.

The proposed rule included the following timing requirements for the allocation of NO_X allowances: by September 30, 1999, each participating State would submit NO_X allowance allocations to EPA for the control periods in the years 2003, 2004, 2005, 2006, and 2007. After the initial allocation, two timing requirements were proposed for allocations following the year 2007. The option set forth in the proposed Model Rule would require a State to submit allocations to EPA for the control period in the year that is 5 years after the applicable submission deadline. For example, by January 1, 2003 each State participating in the trading program would issue its allocations for the control period in 2008. The State would issue allocations for the 2009 summer season by January 1, 2004. The second option, discussed in the preamble of the supplemental notice, would require the State to submit five years' worth of allowance allocations at a time, every five years, starting in 2003. For example, by January 1 , 2003, each State participating in the trading program would issue allocations for the control periods in the years 2008 through 2012. The supplemental notice solicited comment on these timing options as well as the full range of possible timing requirements (including a single, permanent allocation system and an annually changing allocation system). The supplemental notice also solicited comment on a provision requiring EPA to allocate NO_X allowances to NO_X budget units if a State were to fail to meet the timing requirements.

Comments: Although comments covered the entire range of possible timing requirements, commenters generally supported striving for administrative simplicity and ensuring sufficient planning horizons for affected sources, while still addressing the needs of a changing marketplace. Most comments fell into one of five categories.

First, a few commenters favored the option set forth in the proposed Model Rule that would update the allocations each year, five years in advance of the applicable control period. However, most of these commenters also supported a system which would update the allocations less than five years prior to the applicable control period as that would allow more recent data to be used in the allocations. One commenter advocated allocating for the previous season based on current year data (i.e., allocations would be issued at the end of the season for the preceding control period).

Approximately ten commenters favored the approach which would issue allowances five to ten years in advance. This group found that five to ten years of allocations satisfies the desire to have a sufficient planning horizon while still ensuring responsiveness to changing market conditions. Utilities generally opposed allocating single year allowances as it might be disruptive to utility planning.

The third category of commenters advocated longer term or permanent allocations. Most utility and business commenters favored allocations that were issued in ten year blocks at a minimum to provide sufficient time to plan future activities and amortize investments. A report submitted by a State proposed that allocations extend over the capital life of equipment, which was at least ten years.

A fourth set of commenters, which included three States, favored shorter term allocations. These States commented that they may want to base their allocations on more recent data than that proposed by the Model Rule and suggested that three years would provide sufficient planning time for sources. One State suggested tying allocations to the submission of triennial inventories.

A final group of commenters suggested that no timing requirement was necessary. They suggested that just as sources may participate in an interstate trading program with allocations based upon different methodologies, those same sources may participate in such a program even if they receive their allowances at different times or for different periods.

Several State commenters asserted that September 1999 was too early to have allocations set. These States suggested that the allocation process is difficult and takes longer than one year. One State suggested that the early allocation deadline would effectively prevent States from issuing allowances based upon output for the first period because an output approach could not be developed in time.

Response: Most commenters supported issuing allowances at least a couple of years prior to the season in which they would be used. The commenters generally cited the goal of balancing changing market conditions with providing sufficient planning horizons, as had the Agency in the proposal. The EPA agrees that the certainty in having allowances at least a couple of years into the future would provide some predictability for sources in their control planning and build confidence in the market. Most of the State commenters suggested three years prior to the control season as an adequate length of time for sources to know their allocations. The Agency agrees that a trading system could work with sources knowing their allocations three years prior to the control season. Therefore, EPA has modified its original proposal to ensure that sources would always have allowances at least three years in advance of the use date.

In addition to addressing how many years in advance the allocations are determined, the Agency has also considered whether allocations should be issued one control period at a time or for multiple control periods at a time (e.g., five to ten control periods). In response to the comments received, the Agency has determined that it would be appropriate to set minimum timing requirements rather than prescribing a set length of time for all States. Therefore, the Agency is now requiring States choosing to participate in the NO_X Budget Trading Program to allocate a minimum of one summer season of allowances at a time (at least three years in advance of the applicable control period).

Moving from requiring five summer seasons of allocations (three years in advance of the first season) to one summer season of allocations (three years in advance) has the advantage of allowing the allocation system to be updated sooner with more recent data. This would provide those States that want to use updating systems to more fully avail themselves of an updating system. The system could also incorporate new sources more quickly, thus reducing the need for larger new source set-asides.

However, the Agency has determined that a State may decide to issue allowances further into the future than the one-season minimum period required by this final rule and still receive streamlined EPA review of its trading program. The NO_X Allowance Tracking System will be able to handle allocations for longer periods. Therefore, this Final Rule sets out minimum timing requirements of one season (three years in advance), but States may issue allocations in larger blocks for as many as 30 seasons into the future and still receive streamlined EPA review. However, in determining the length of time for which a State issues allocations, a State should consider any potential adjustments that may occur to its future State budgets. For example, as stated in Section III.B.5.

of this preamble, the Agency may establish new budget levels for the post-2007 timeframe. States issuing long-term allocations should address how the allocations would be adjusted if new budget levels are established in the future. The Agency does believe that having allocations three years prior to the relevant control period would be the minimum needed to support an active multi-state trading market intended to reduce compliance costs for all States involved.

The three-year minimum timing requirement also is compatible with beginning the program in 2003, with at least the first year's allocations submitted to EPA by September 30, 1999. Sources will know their first year's allocations three years prior to the start of the program, and by April 1, 2003, all sources will have allocations for at least four seasons—2003, 2004, 2005 and 2006. The Agency maintains that the first year's allowances should be issued by September 30, 1999 to provide some predictability for sources in their control planning and build confidence in the market. It also ties in with the State's SIP submittal deadlines. For States participating in the trading program, the allowances are an integral part of the State's plan to satisfy the requirements of this SIP call. For sources in the Trading Program, the allowances are the mechanism by which State budget requirements are translated into source-specific limitations, and therefore the allocations should be submitted with the SIP submittals. In response to States who are worried about completing allocations in this time frame, EPA notes that one State in the OTC resolved its allocations in six weeks, demonstrating that it is possible to establish allocations in less than one year.

Requiring only one year's worth of allowances at a time has the added benefit of being able to more quickly accommodate States that want to switch allocation methodologies after the start of the program. For example, a State may decide to issue its initial allocations based on heat input data because it has not yet finalized an approach to issuing output-based allocations. The State could take a few additional years to refine the alternative approach to issuing allowances. When the State is ready to adopt the output approach, the State would be able to start using the new approach much sooner than it would be able to under a system that issued allocations in larger blocks.

Therefore, this preamble sets the following timing requirements for the allocation of NO_X allowances which will be able to accommodate States that want to issue allocations one year at a time as well as States that would like to issue allocations in larger blocks: by September 30, 1999, the State would submit NO_X allowance allocations to EPA for at least the control period of 2003. After this initial allocation, by April 1 of every year starting in 2001, the State must, at a minimum, submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. For example, by April 1, 2001, a State would submit allocations for the control period in 2004. By April 1, 2002, a State would submit allocations for the control period in 2005. This minimum requirement would allow a State to submit blocks of allowances that represent any number of years should the State prefer to do so. For example, by the September 30, 1999 deadline, a State could submit allocations for only the 2003 control period or for multiple control periods (e.g., the five control periods of 2003–2007). The SIP would provide that if the State fails to submit allocations by the required date, EPA would allocate allowances based on the previous year's allocation within 60 days of the applicable deadline. This approach would ensure that starting in 2003, all sources would always have at least three years of allowances in their accounts.

Today's Model Rule presents an allocation approach that satisfies the minimum timing requirements. However, the initial allocation is for three control periods (2003–2005) because this would avoid updating allocations on an input basis. Any variation on the following approach would be acceptable providing it satisfies the minimum requirements specified in the previous paragraph. After this initial allocation, the model rule would have the State submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. By April 1, 2003, a State would submit allocations for the control period in 2006. By April 1, 2004, a State would submit allocations for the control period in 2007, and so forth.

2. Options for NO_X Allowance Allocation Methodology

The Agency proposed that the NO_X Budget Trading Rule include a recommended NO_X allowance allocation methodology. The proposed Model Rule laid out an example of an allocation methodology using heat input data for source allocations. The preamble to the proposed Model Rule solicited comment on this methodology as well as two additional options using either input or output data for determining allocations. The first alternative to using heat input would base the allocation recommendation on heat input data for the first five control periods of the trading program and then convert the allocations to an output basis for the control periods after 2007. The final option would base the allocation recommendation on output data for all NO_X Budget units from the start of the trading program. The Agency also solicited comment on a suggested schedule for establishing a method for output-based allocations, and on any technical or data issues relevant to output-based allocations, as well as on the use of a fuel-neutral or output-neutral calculation to determine allocations for NO_X Budget units.

Comments: The Agency received numerous comments on the issue of whether to suggest an allocation recommendation to States. Approximately 25 commenters suggested that no recommendation is necessary. Many of these commenters emphasized that EPA had no authority to prescribe an allowance allocation methodology and a recommendation could be misinterpreted as a requirement for SIP approval. Several commenters requested that EPA clarify that the SIP approval process will be consistently applied to all States regardless of the allocation method chosen by a State, as long as the total allocation does not exceed a State's trading budget. Approximately half of the commenters who stated that no recommendation was necessary suggested that if EPA were going to make a recommendation, the recommendation should be a heat input approach.

Close to fifty commenters suggested that an Agency recommendation was a good idea, but they were divided on the appropriate methodology. This group included all the State commenters who suggested that a recommended approach was appropriate for use as a default allocation mechanism by States that did not determine their own allocations.

Many commenters supported the heat input approach used in the example in the supplemental notice. Two State commenters said that the proposed example approach was a useful default for States that did not come up with their own allocations. Other commenters suggested that heat input is an easily understood metric for all sources and the data is readily available.

However, many suggested that EPA should recommend an output method because they believe output-based allocations tend to reward more efficient

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fuels over fuels that require a higher heat input to generate the same amount of electricity. Other reasons cited for output-based allocations include the incentive that updating output allocations provides for reducing emissions of pollutants such as CO_2 and mercury. Several commenters suggested that output-based allocations would allow the environmental goals of the program to be achieved more cost-effectively; their arguments rested upon assertions that issuing allowances to non-NO_X emitting units in an output-based system would reduce the need for NO_X controls over time. One State commenter said that an output approach was the consensus of participants at EPA Workshops held prior to drafting of the Supplemental Notice and therefore should be the recommended approach suggested by EPA.

One commenter had a specific recommendation for an updating output-based allocation system which would issue allowances each year for the current control period. Administrative simplicity, economic efficiency, incentives for innovation, and lower consumer impact were cited as reasons supporting that position.

Additional commenters favored the output-based approach but only for fossil-fuel fired sources and renewables. Several commenters submitted letters opposing a ''fuel-neutral'' policy and objected to including nuclear sources in an output allocation to sources. They stated that a fuel neutral policy would provide incentives for nuclear generation which has the potential to release small amounts of radiation to the environment as well as the potential for generation of high-and low-level radioactive waste.

Response: As was stated in the SNPR, EPA believes that it is important for as many States as possible to participate in the NO_X Budget Trading Program. The Agency recognizes that States have unanimously favored flexibility in developing their own allocation methodologies. Further, the comments that EPA received in response to the SNPR (as well as in response to the workshops held prior to publication of the SNPR) provided no clear consensus for one methodology over another.

However, the Agency believes it is important to provide a model allocation methodology that States may choose to use as a guide for their own allocation process. Several States have commented that including an example method in the Model Rule would be useful as a backup for States who do not come up with an alternative method of allocation. An outlined approach in the Model Rule may also facilitate the regulatory process within a State that wants to quickly adopt the Model Rule.

Therefore, today's Model Rule includes an optional allocation methodology. The Agency has carefully considered arguments for alternative allocation methods. The EPA would support a decision by a State to use either heat input or output data as a basis for source allocations or for the State to auction some or all of its allocation. In determining the basis for the methodology presented in today's Model Rule, EPA has decided to use the heat input approach because it is concerned that an output-based approach has not been fully developed or made available for public comment. Further, before issuing a model output-based allocation approach, the Agency would need to make several revisions to current reporting and monitoring provisions. EPA would have to revise part 75 to monitor and report temperature, pressure, and steam heat output (mmBtu) for units with some or all of their output as heated steam. EPA would also need to put in place procedures which take advantage of the most accurate data possible. For example, the Energy Information Administration (EIA) solicited comment in a July 17, 1998 **Federal Register** Notice on a proposal to make electricity generating data non-confidential and publicly available from non-utility electricity generators (63 FR 38620). EPA will not know if this information is available to the Agency or to States through EIA for some time. If EIA were to decide that this information should remain confidential in the future, then EPA and States would need to collect their own data from sources. Additionally, the Agency is currently unaware of any public databases of output information besides those for electrical generation output for certain electrical generating units. Output information would only become available if sources report it directly to the Agency or to States.

While today's final Model Rule includes a heat input approach, the Agency is continuing to work on developing an updating output approach to source allocations. For States that wish to use output in developing their source allocations and are willing to wait for EPA to finalize such an approach, EPA plans to issue a proposed system for output-based allocations in 1999 and finalize an output-based option in 2000. However, the Agency's ability to issue an output- based approach on this schedule is contingent upon resolving the issues and promulgating the necessary rule changes mentioned in the previous paragraph.

Assuming EPA finalizes an output-based option in early 2000, States wishing to use this output-based system could adopt the necessary rules, and output data could be measured and collected at NO_X budget units during the control periods in the years 2001 and 2002. Output data could then be available for States to calculate allocations for the control periods starting in 2006. Heat-input-based allocations could be used for the 2003 through 2005 control seasons.

However, this does not prohibit a State from developing its own output-based system on a faster timeline. For example, if a State has developed an output-based approach for use in its initial allocations, it may use that approach. Or, the State may issue its initial allocation for 2003 using heat input data and then by April 1, 2001 issue output allocations for the control periods starting in 2004.

The Agency recognizes that a State's choice of when and for what blocks of time it issues allocations is intertwined with the choice of allocation methodology. Several commenters suggested that more incentives for generation efficiency and therefore ancillary environmental benefits (CO_2 and mercury reductions) are provided in an output system with periodic updates, and those incentives are lost in an heat input system that is periodically updated. These commenters suggested that with a heat-input-based system, States should issue permanent allocations rather than updating the allocations. An allocation system that issues permanent streams of allowances (using either a heat input or an output methodology) would still provide an incentive for generation efficiency although perhaps not to the extent that an updating output system might. However, if a State issues a permanent stream of allowances to existing sources, that State would have to decide how to address new sources (options include establishing an allocation set aside or an auction, or requiring new sources to obtain allowances from existing sources).

3. New Source Set-Aside

The Agency proposed an allocation set-aside account equaling 2 percent of the State trading program budget for each control period for new NO_x Budget units as part of its recommended allocation approach. The concept and size of the set-aside is included only as an optional feature of the Model Rule; however, the Model Rule requires new sources to hold allowances to cover

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their emissions. The supplemental notice proposed that allowances from the set-aside be given out on a first-come, first-served basis at an emission rate of 0.15 lb/mmBtu multiplied by a budget unit's maximum design heat input. The source would then be subject to a reduced utilization calculation so that a reduction in the emission rate below 0.15 lb/mmBtu would be rewarded, but a reduction in utilization would not. In other words, EPA would deduct NO_x allowances following each control period based on the unit's actual utilization for the control period. After the deduction, the allocation that had been granted to the new unit from the set-aside would equal the product of 0.15 lb/mmBtu and the budget unit's actual heat input for the season. EPA solicited comments on the use of a set-aside as part of the recommended allocation methodology as well as the proposed size and operation of the set-aside.

Comments: The Agency received many comments regarding the proposal for a new source set-aside. While several commenters were opposed to a new source set-aside because it might bias control decisions in favor of adding new sources relative to controlling existing sources, numerous other commenters expressed general support for accommodating new sources with allowances.

Several of these commenters offered suggestions for how the set-aside should be designed. A few commenters stated that the size of the set-aside should be related to the timing requirements and noted that shorter timing requirements make it easier to accommodate new growth. One commenter who advocated annually updating the allocation system noted that its proposal would eliminate the need for a new source set-aside. Some commenters supported the set-aside concept but asserted that States should be able to decide the correct size. Other commenters agreed with the set-aside concept in theory but did not think the allowances should come from existing sources.

Additional commenters had specific proposals for the size of the set-aside. One commenter suggested that the size of the set-aside should reflect the actual growth projected in budget calculations and that the unused portion of the set-aside should be retired. A few commenters agreed with the proposed 2 percent size.

Several commenters offered suggestions on how to issue the set-aside allowances to new sources. One commenter suggested that the allowances should be given to new sources at the actual emission rate if it was below the proposed 0.15 lb/mmBtu level.

Finally, several commenters suggested that the concept of a set-aside was an issue that should be left completely up to the States.

Response: The Agency believes that a new source set-aside should be large enough to provide all new units entering the trading program with allocations. The Agency maintains that as much as possible within the context of the overall trading budget, allocations should be provided to new sources on the same basis as that used for existing units until the time when the new sources receive an allocation as part of an updating allocation system. Therefore, the Agency continues to include a new source set-aside as part of its optional allocation methodology described in the Model Rule. The EPA proposed the 2 percent set-aside in the SNPR after looking at the amount of growth from new sources projected by the Integrated Planning Model (and used in the budget determinations) and estimating how much growth could be expected over the five year period that new sources might have to wait before receiving an allocation. In light of the allocation methodology and timing specified in today's Model Rule as well as revisions made to the growth factors used in State budget determinations since the SNPR, the Agency has re-evaluated the size of the new source set-aside proposal. The revised Integrated Planning Model projects approximately ½ percent annual growth in capacity utilization for new sources. Given the timing and optional allocation methodology specified in today's Model Rule, the 2003, 2004, and 2005 set-aside would need to accommodate any source that started operating after May 1, 1995. Assuming the ½ percent growth rate projected by IPM, the Agency finds that a 5 percent set-aside should be large enough to accommodate all new sources for the 2003, 2004, and 2005 control seasons.

After 2005, the new source set-aside would need to accommodate any source that commenced operation after May 1 of the control period three years prior to the control period in which the set-aside would be available. For example, in 2006, the set-aside should be large enough to accommodate any source that commenced operation after May 1, 2003. Assuming the growth rates predicted by the IPM, the Agency finds that a 2 percent set-aside should be large enough to accommodate new source growth after May 1, 2003.

A 5 percent set-aside provision for the first three control seasons and 2 percent for the control periods starting in 2006 is incorporated into today's Model Rule as an option States may adopt. However, States may choose to handle new sources in any way as long as the emissions from new sources are subject to the overall State budget. For example, some States may choose to issue allowances for longer periods of time than that outlined as the minimum requirement in today's Model Rule. These States may find that a 5 percent set-aside is not sufficient to accommodate all their new source growth, and may want to consider a larger set-aside or alternative means to accommodate new sources. Or, States may decide to allocate allowances based on a new source's permitted or actual emissions, which may be lower than 0.15 lb/mmBtu. This would require a smaller set-aside.

In the model rule set-aside provision, allowances will be issued to new sources on a first-come, first-served basis. Allowances that are not issued to new sources in the applicable control period will be returned to the existing sources in the State on a pro-rata basis to guard against the possibility of a disproportionately large set-aside.

The EPA maintains its position that new sources should receive allowances at the same rate as that applied to existing sources (i.e., large electric generating units would receive allowances at a 0.15 lb/mmBtu rate, large non-electric generating units would receive allowances at the average emission rate for existing large non-electric generating units after controls are in place, as explained in section 4 below). However, to reinforce the flexibility available on these issues, as long as a State requires new sources to hold allowances, the Agency reiterates that States may have any size set-aside (including zero), may allocate the set- aside in whatever manner they choose, and may carry over from one year to the next any amount of allowances (subject to the banking provisions on this SIP call). If a State decides to return unused allowances from a new source set-aside to existing sources, the State would indicate to EPA (as the administrator of the allowance tracking system) what number of allowances should be returned to which existing units.

4. Optional NO_X Allocation Methodology in Model Rule

While specific source allocations are required for States participating in the NO_X Budget Trading Program, the allocation methodology presented here is an optional approach that may be adopted by States. As long as a State (1) does not allocate more allowances than are available in the State NO_X trading

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budget, (2) requires new sources to hold allowances, and (3) issues allocations on a schedule that meets the minimum timing requirements, the State may adopt whatever methodology it finds the most appropriate and still qualify for inclusion in the NO_X Budget Trading Program.

The Model Rule contains the following optional allocation methodology. It differs from the approach presented in the proposed rule on the timing provisions, the allocation methodology for non-electric generating units, and the size of the optional new source set-aside. As proposed in the SNPR, initial unadjusted allocations to existing NO_X Budget units serving electric generators would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.15 lb/mmBtu. For the control periods in 2003, 2004, and 2005, the heat input used in the allocation calculation for large electric generating units equals the average of the heat input for the two highest control periods for the years 1995, 1996, and 1997. Once the State completes the initial allocation calculation for all the existing NO_X budget units serving electric generators for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's NO_X Budget units serving electric generators. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's NO_X Budget units serving electric generators (to provide for the 5 percent new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation for large electric generating units equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to NO_X Budget units serving electric generators, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to NO_X Budget units serving electric generators (to provide for the 2 percent new source set-aside).

For reasons explained elsewhere in today's rulemaking, EPA determined the aggregate emission levels for large non-electric generating units in each State budget based upon a 60 percent reduction rather than the 70 percent proposed in the SNPR. The 60 percent reduction results in an average emission rate across the region of 0.17 lbs/mmBtu for large non-electric generating units. Therefore, initial unadjusted allocations to existing large non-electric generating units would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.17 lb/mmBtu. For non-electric generating units subject to the trading program, 1995 heat input data is used in the allocation calculation for the control periods 2003, 2004, and 2005 (1995 is the most recent data the Agency knows is currently available for non-electric generating units). Once the State completes the initial allocation calculation for all the existing large non-electric generating units for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's large non-electric generating units. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's large non-electric generating units (to provide for the 5 % new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to large non-electric generating units, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to large non-electric generating units (to provide for the 2 % new source set-aside).

A State would establish a separate allocation set-aside for new units each control period. Five percent of the seasonal trading budget will be held in a set-aside account for the control periods in 2003, 2004, and 2005. At the end of the relevant control period, the State would submit a NO_X allowance transfer request to EPA to return any allowances remaining in the account to the existing sources in the State on a pro-rata basis.

The allowances would be issued to new sources on a first-come first-served basis at a rate of 0.15 lb/mmBtu for NO_X Budget units serving electric generators and 0.17 lb/mmBtu for large non-electric generating units multiplied by the budget unit's maximum design heat input. Following each control period, the source would be subject to a reduced utilization calculation, in which EPA would deduct NO_X allowances based on the unit's actual utilization. Because the allocation for a new unit from the set-aside is based on maximum design heat input, this procedure adjusts the allocation by actual heat input for the control period of the allocation. This adjustment is a surrogate for the use of actual utilization in a prior baseline period which is the approach used for allocating NO_X allowances to existing units.

F. Banking Provisions

As explained in Section III.F.7., EPA requested comment in the SNPR on whether and how banking should be incorporated into the design of the NO_X Budget Trading Program. Banking may generally be defined as allowing sources that make emissions reductions beyond current requirements to save and use these excess reductions to exceed requirements in a later time period. Options ranged from a program without banking to several variations of a program with banking, prior to and/or following the start of the program. The EPA also requested comment on options for managing the use of banked allowances in order to limit the emissions variability associated with banking. The EPA specifically proposed using a ''flow control'' mechanism in cases where the potential exists for a large amount of banked allowances to be available.

This section addresses how banking has been incorporated into the NO_X Budget Trading Program based on the criteria set forth in the NO_X SIP call.

1. Banking Starting in 2003

In accordance with the provisions discussed in III.F.7.a., trading programs used to comply with the NO_X SIP call may allow banking to start in the first control period of the program, the 2003 ozone season. The majority of commenters supported banking in the context of the NO_X Budget Trading Program. Based on the advantages that banking can provide, as discussed in the SNPR and the comments, the NO_X

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Budget Trading Program has been designed to allow banking starting in the first control period of the trading program. NO_X Budget units that hold additional NO_X allowances beyond what is required to demonstrate compliance for a given control period may carry-over those allowances to the next control period. These banked allowances may be used or sold for compliance in future control periods.

2. Management of Banked Allowances

The NO_X SIP call establishes that a flow control mechanism be paired with any banking provisions to limit the potential for emissions to be significantly higher than budgeted levels because of banking. This mechanism allows unlimited banking of allowances saved through emissions reductions by sources, but discourages the ''excessive use'' of banked allowances by establishing either an absolute limit on the number of banked allowances that can be used each season or a rate discounting the use of banked allowances over a given level. In the SNPR, EPA solicited comment on the application of flow control in the NO_X Budget Trading Program. Although many commenters were opposed to any restrictions on the use of banked allowances, several commenters stated that if restrictions were to be imposed, they would favor flow control as the most cost-effective, least rigid means of management. A few commenters added that, if implemented, flow control should be applied on a source-by-source basis so as to avoid penalizing all of the participants in the trading program for the excess banking of individual participants. One commenter stated that if EPA concludes that there is an adequate basis for imposing some type of restriction, it should avoid placing any absolute limit on the amount of banked allowances that can be used in a given season.

The NO_X SIP call established that flow control should be set at the 10 percent level. The effect of setting flow control at 10 percent of the trading program budget is that on a season-by-season basis, sources may use banked allowances or credits for compliance without restrictions in an amount up to 10 percent of the NO_X budget for those sources in the trading program. Banked allowances or credits that are used in an amount greater than 10 percent of the NO_X budget for those sources will have restrictions on their use.

The following provides a brief description of exactly how the flow control mechanism will operate in the NO_X Budget Trading Program. The number of banked allowances held by all participants in the multi-state trading program will be tabulated each year following the compliance certification process to determine what percentage banked allowances are of the overall multi-state trading budget for the next year. If this percentage is equal to or below 10 percent, all banked allowances may be used in the upcoming control season on a one allowance for one ton basis. If this percentage is greater than 10 percent, flow control will be triggered. In years when flow control is triggered, a withdrawal ratio will be established prior to the control period for which it would apply. The withdrawal ratio will be calculated by dividing 10 percent of the total trading program budget by the total number of banked allowances. This ratio will be applied to each compliance or overdraft account (only accounts used for compliance) holding banked allowances as of the allowance transfer deadline at the end of the control period for which it applies. Banked allowances in each account may be used for compliance on a one-for-one basis in an amount not exceeding the amount established by the withdrawal ratio. Banked allowances used in an amount exceeding that established by the withdrawal ratio must be used on a two-for-one basis. By setting the withdrawal ratio prior to the applicable control period (in years flow control is triggered) and applying it at the time of compliance certification at the end of the applicable control period, sources have one full control period to incorporate the value of using banked allowances into their operations.

As described above, the NO_X Budget Trading Program applies the flow control mechanism on a regional basis and establishes a 2-for-1 discount for banked allowances that are used in an amount greater than the flow control limit. The regional approach for applying flow control was selected over the source-by-source approach for the following reasons:

- EPA believes this option provides more flexibility to individual sources than the source-by-source approach. If the 10 percent limit were placed on each source based on the source's allocation, the limit would be in effect every year for every source, even when the amount of banked allowances throughout the entire trading region was below 10 percent of the regional trading budget. In contrast, the regional approach only applies flow control when the amount of banked allowances throughout the region (entire multi-state trading area) exceeds the 10 percent limit. In response to the commenter suggesting that the regional approach penalizes all participants in the trading program for the excess banking of individual participants, EPA notes that it would be difficult for a few sources to cause the entire regional bank to exceed 10 percent of the budget. In addition, based on the analyses presented in the RIA, EPA does not anticipate that flow control is likely to be triggered. Consequently, flow control is more of an insurance policy, rather than a provision that is routinely expected to be operational.
- The regional approach also provides flexibility to sources if and when it is triggered. Because the withdrawal ratio is set before the applicable control period but not applied until the control period's allowance transfer deadline, sources have over seven months to manage the amount of banked allowances they use on a 1-for-1 basis versus a 2-for-1 basis.
- EPA believes the regional approach is also a more universal approach than the source-by-source approach under a variety of allocation programs that States may use in the NO_X Budget Trading Program. To apply the flow control mechanism on a source-by-source basis, the 10 percent limit would be applied to each source's allocation. In this way, a source could use an amount of banked allowances up to 10 percent of it's allocation without restrictions. Restrictions would be placed on banked allowances that the source uses in an amount greater than 10 percent of its allocation. Under certain allocation programs, States may choose not to allocate NO_X allowances to new sources and require that these sources obtain the necessary amount of NO_X allowances for compliance from the market. By not having an allocation of NO_X allowances, new sources would be prevented from using banked allowances under the source-by-source approach. EPA believes that approaches to accommodate sources without a fixed allocation under the source-by-source flow control approach would overly complicate the system.
- The regional approach for applying flow control is also the approach used in the Ozone Transport Commission's (OTC) trading program. Because the NO_X Budget Trading Program is designed to include States currently operating in the OTC program, using the same approach for flow control will minimize the disruption for these sources to convert to the NO_X Budget Trading Program.

The other issue for flow control is the type of restriction to place on banked allowances used in an amount greater than the 10 percent limit. The NO_X Budget Trading Program includes the 2-for-1 discount as the applicable

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restriction. EPA agrees with the commenters that favored this approach over using an absolute limit. The EPA believes the 2-for-1 discount provides more flexibility for sources to achieve compliance than is offered by the absolute limit. The discount is also beneficial to the environment, when triggered, by allowing only one ton of NO_X emissions for every two tons removed. Additionally, the OTC program uses the 2-for-1 discount.

The following example illustrates how flow control will be used. For the year 2006, assume the total trading program budget across all States equals 300,000 allowances and 35,000 allowances are banked from control periods prior to the 2006 control period. Since more than 10 percent (35,000/300,000 = 11.7 %) of the total trading program budget is banked, a withdrawal ratio will be established prior to the 2006 control period and will apply to all compliance and overdraft accounts (only accounts that may be used for compliance) holding banked allowances at the end of the 2006 control period. In this case, the withdrawal ratio would be 0.86 (determined by dividing 10 percent of the total trading program budget by the total number of banked allowances, or 30,000/35,000). Thus if a source holds 1,000 banked allowances at the end of the 2006 control period, it will be able to use 860 on a 1-for-1 basis, but will have to use the remaining 140, if necessary, on a 2-for-1 basis. As a result, if the source used all its banked allowances for compliance in the 2006 control period, the 1,000 banked allowances could be used to cover only 930 tons of NO_X emissions (860 + 140/2). Of course, a source could buy additional current year allowances to cover emissions on a 1-for-1 basis or buy additional banked allowances (allowances not needed by other sources for compliance) to increase the amount of banked allowances it may use on a 1-for-1 basis.

3. Early Reduction Credits

As described in section III.F.7.c., the majority of commenters generally supported the option of awarding early reduction credits. EPA is allowing, but not requiring, States to grant early reduction credits to sources for reductions in ozone season NO_X emissions prior to the 2003 ozone season. States may issue early reduction credits in an amount not exceeding the State's compliance supplement pool. The compliance supplement pool is further explained in section III.F.6.

Based on the support the commenters on the NO_X Budget Trading Program expressed for early reduction credits, EPA is including optional provisions in the trading program that States may use for issuing credits. States participating in the NO_X Budget Trading Program that choose to issue early reduction credits may follow the methodology included in part 96 or may develop their own methodology, provided the State's program meets the following requirements. The State program must ensure that early reduction credits will not be issued in an amount exceeding the State's compliance supplement pool. The State program must also meet the criteria for early reduction credits discussed in section III.F.7.c. Finally, the State should notify EPA of the amount of credits issued to particular NO_X Budget units by no later than May 1, 2003. Early reduction credits shall be issued to units as allowances for the 2003 control period. For purposes of the banking provisions, the allowances will not be considered banked in the 2003 control period. However, any unused allowances carried from the 2003 control period to the 2004 control period shall be considered banked as will be the case for all unused allowances carried over to the next control period. Per the requirements discussed in section III.F.7.c., allowances issued for early reduction credits may be used for compliance by sources in the 2003 and 2004 control periods. Any of these allowances that are not used for compliance in the 2003 or 2004 control periods shall be retired by EPA from the account in which they are held.

As discussed in Section III.F.6.b.ii., States also have the option of issuing some or all of the State's compliance supplement pool directly to sources according to the criteria for direct distribution. Consequently, States participating in the NO_X Budget Trading Program may also use the direct distribution option for issuing the compliance supplement pool. In this case, the State must notify EPA by May 1, 2003 of the specific NO_X Budget units that will be receiving the direct distribution.

4. Optional Methodology for Issuing Early Reduction Credits

The methodology described below is an optional methodology included in part 96 that States participating in the NO_X budget Trading Program and choosing to issue early reduction credits may follow. States participating in the NO_X Budget Trading Program may also choose to develop their own methodology as discussed above. The following methodology is designed to meet the criteria for issuing early reduction credits discussed in section III.F.7.c. and to provide incentives for a State's NO_X budget units to generate early credits in an amount no greater than the size of the State's compliance supplement pool. The State may choose to issue the entire compliance supplement pool as early reduction credits through this methodology, or the State may choose to reserve some of the compliance supplement pool to be issued to sources according to the direct distribution criteria as described above.

This methodology is applicable for reductions made during the 2001 and 2002 ozone seasons. NO_X budget units that request early reduction credits will be required to monitor ozone season NO_X emissions according to the monitoring provisions of part 75, subpart H by the 2000 ozone season. The information from the 2000 ozone season shall be used to establish a baseline emission rate for the NO_X budget unit. To be eligible for early reduction credits, a NO_X budget unit shall reduce its emissions rate in the 2001 and/or 2002 control period(s) no less than 20 percent below its baseline emissions rate established for the 2000 ozone season. The size of the early reduction credit request shall equal the difference between 0.25 lb/mmBtu and the unit's actual emissions rate multiplied by the unit's actual heat input for the applicable control period. NO_X Budget units requesting early reduction credits should submit the request to the State by no later than October 30 of the year for which the early reductions were generated.

The methodology conforms with the NO_X SIP call's criteria for early reduction credits. By requiring that the reductions be measured using provisions in part 75, the reductions will be verified as having actually occurred and will be quantified according to the same procedures as required for compliance with the general requirements of the NO_X Budget Trading Program. The procedure for calculating the credit request is intended to ensure that the reductions are surplus. Phase II of the title IV NO_X emissions limits are required to be installed at specific coal-fired boilers by January 1, 2000. By requiring that an early reduction credit must be generated by no less than a 20 percent reduction below the 2000 baseline emission rate, credits will only be issued for reductions that go below emissions levels achieved for compliance with title IV requirements. This provision ensures that the early reduction credits are only issued for reductions below existing requirements (i.e., surplus).

Calculating the early credit based on the difference between 0.25 lb/mmBtu

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and the unit's actual emissions rate establishes a standard emissions rate from which all early reduction credits are calculated. This approach ensures that sources with higher NO_X emissions rates prior to the 2001 ozone season are not provided an opportunity to generate more early reduction credits than relatively cleaner sources. In this way, all sources have an equal opportunity to generate early reduction credits below a standard emissions rate.

According to the requirements in the NO_X SIP call, States may not issue early reduction credits in an amount greater than the State's compliance supplement pool. To ensure this provision is met, the optional methodology is designed for States to issue all early reduction credits following the 2002 ozone season. By October 30, 2002, a State will have received all early reduction requests for both the 2001 and 2002 ozone seasons. After review of the requests, the State would issue credit to all valid requests according to the following procedure. If the amount of valid requests is less than the size of the State's compliance supplement pool, the State would issue one allowance for each ton of early reduction credit requested. If the amount of valid requests is more than the size of the State's pool, the State would reduce the amount in the credit requests on a pro-rata basis so that the requests equal the size of the State's pool. After the requests have been reduced, the State would then issue allowances based on the remaining size of each credit request. States would complete the issuance of allowances for the early reduction credit requests as soon as possible following October 30, 2002, but no later than May 1, 2003.

5. Integrating the OTC Program With the NO_X Budget Trading Program's Banking Provisions

The OTC NO_X Budget Program is a multi-state, capped NO_X trading program that begins in 1999 and includes many States subject to today's action. By the start of the NO_X Budget Trading Program under the NO_X SIP call, sources in the OTC program will potentially hold banked NO_X allowances resulting from early reductions and/or overcontrol with program requirements. At issue is the ability of OTC sources to use these banked allowances in the NO_X Budget Trading Program.

Commenters have supported allowing OTC sources to use banked allowances (i.e., early reductions from the 1997 and 1998 ozone seasons and unused allowances from the 1999 through 2002 ozone seasons) from the OTC program for compliance in the NO_X Budget Trading Program. Commenters have stated that because OTC sources will be subject to a market-based cap-and-trade program prior to the 2003 ozone season, it is important to create a smooth transition from the OTC program to the NO_X Budget Trading Program. They have suggested discounting OTC Phase II allowances to make them equivalent to those achieved under the NO_X SIP call. One OTC State suggested accomplishing this by adjusting the OTC banked allowances by a ratio of the Phase II OTC control requirement to the Phase III OTC control requirement, working with EPA to determine the exact ratio. A few OTC States suggested that OTC allowances banked in Phase II could be used as early reduction credits in the NO_X Budget Trading Program. A commenter from outside the OTC voiced concern that the use of OTC allowances banked by sources for the years 1999 through 2002 could distort the larger trading market established under the SIP call.

The EPA believes that the compliance supplement pool provides the opportunity to integrate the OTC program into the NO_X Budget Trading Program by allowing OTC States to bring their banked allowances into the NO_X Budget Trading Program as early reduction credits after the 2002 ozone season. The EPA established two primary criteria for the generation of early reduction credits in III.F.7.c.: first, the credits must be surplus, verifiable, and quantifiable; and second, a State may not grant an amount of early reduction credits in excess of a State's compliance supplement pool. EPA believes that banked allowances held by sources in the OTC program would qualify as being surplus, verifiable, and quantifiable. The banked allowances would be surplus because they would represent emissions reductions that go beyond what is required by the emissions limitations established by the OTC program in the applicable ozone seasons. The banked allowances would also be verified and quantified according to the procedures in the OTC program which are essentially identical to the requirements that will be in place under the NO_X Budget Trading Program.

As for the second criterion that a State issue no more early reduction credits than provided through the compliance supplement pool, EPA believes this could be addressed according to the following procedure. If the number of banked allowances held by an OTC State's NO_X Budget units, after the compliance certification process for the 2002 ozone season, is less than the number of credits available in the pool for that State, the NO_X budget units in that State may carry all of their banked allowances from the OTC program into the NO_X Budget Trading Program. The banked allowances brought in from the OTC program would be subtracted from the State's compliance supplement pool. Any remaining credits in the compliance supplement pool could be distributed by the OTC State through the direct distribution option, if necessary. If, on the other hand, an OTC State's NO_X Budget units hold banked allowances from the OTC program in excess of the amount of credits in the State's pool, after the compliance certification process for the 2002 ozone season, the State would need to reduce the amount of allowances eligible for being carried into the NO_X Budget Trading Program. This could be achieved by reducing the amount of banked allowances held by the units on a pro rata basis so that the number of allowances carried into the NO_X Budget Trading Program is less than or equal to the size of the State's compliance supplement pool.

The process described above provides a mechanism for OTC States to use the compliance supplement pool to carry banked allowances from the OTC program as of the end of the compliance period in 2002 over into the NO_X Budget Trading Program. The EPA believes this integration acknowledges the important reductions made in the OTC program prior to 2003 while providing similar opportunities for sources outside the OTC to generate credits for early reductions. Since all States in the NO_X Budget Trading Program will have an opportunity to receive credit for early reductions, EPA does not believe any market distortion will occur.

G. New Source Review

Under the New Source Review (NSR) provisions of section 173 of the CAA, a new major source or a major modification to an existing major source of a particular pollutant that proposes to locate in an area designated nonattainment for that pollutant must offset its new emissions. In the SNPR, the EPA solicited comment on whether and how the offset requirement could be met by sources' participation in the NO_X Budget Trading Program. The Agency stated its belief that sources obligated to obtain NO_X offsets under the NSR program should be able to do so by acquiring NO_X allowances through the trading program. In essence, the EPA reasoned that, where a trading program is a capped system, a new source's acquisition of allowances to cover its increased emissions would necessarily result in actual emissions reductions elsewhere in the system.

The EPA continues to believe that nonattainment NSR offset requirements of the CAA can be met using the mechanism of the NO_X Budget Trading Program. However, there are a number of complex issues involved with integrating these programs, for example, the statutory requirements to obtain offsets from certain geographic areas and, depending on the classification of the 1-hour ozone nonattainment area, at certain offset ratios. Because the Agency is continuing to evaluate these issues, it will not be providing guidance at this time on integrating these programs; however, the EPA intends to provide such guidance as soon as possible. At that time, the EPA will respond to the comments received on this topic in the course of this rulemaking.

VIII. Interaction With Title IV NO_X Rule

The EPA proposed, in the May 11, 1998 supplemental notice, to add a new § 76.16 to part 76, the Acid Rain NO_X Emission Reduction Program regulations. The purpose of the proposed § 76.16 was to increase utilities' flexibility in situations where units owned or operated by a utility were subject to both a NO_X cap-and-trade program and the Phase II NO_X emission limitations under the Acid Rain NO_X Emission Reduction Program. Under proposed § 76.16, a State or group of States could request that the Administrator relieve all units located in the State or States and otherwise subject to the Phase II NO_X emission limitations (under §§ 76.6 and 76.7) of the requirement to comply with such emission limitations. The Administrator could also take this action on his or her own motion. All Group 1 boilers (i.e., tangentially fired or dry bottom wall fired boilers) would remain subject to the Phase I NO_X emission limitations (under § 76.5), while Group 2 boilers (i.e., cell burner boilers, cyclones, wet bottom boilers, and vertically fired boilers) would have no NO_X limits under the Acid Rain Program. This relief would be available if all such units were subject, under a SIP or a FIP, to a NO_X cap-and-trade program meeting certain requirements. The NO_X cap-and-trade program had to include, *inter alia,* either an annual cap or seasonal caps that together limited total annual emissions and a requirement that each unit use authorizations to emit (or allowances) to account for all NO_X emissions. In addition, there had to be a demonstration that total annual NO_X emissions from all units otherwise subject to the Acid Rain NO_X emission limitations and located in the State or group of States would, under the NO_X cap-and-trade program, be equal to or lower than the total number of annual NO_X emissions if the units remained subject to the Acid Rain NO_X emission limitations. Alternative emission limitations and NO_X averaging plans under part 76 would not be taken into account in such a demonstration.

Although the purpose of proposed § 76.16 was to provide more flexibility to utilities consistent with the requirements of section 407, almost all utility commenters and many State and State agency commenters opposed the proposal. Many commenters argued that relieving a utility's units in one State of the applicability of the Phase II NO_X emission limitation would prevent the utility from using those units, along with units that the utility owns or operates in other States, in an interstate averaging plan under the Acid Rain Nitrogen Oxides Emission Reduction Program. Under section 407(e) of the CAA, as implemented under § 76.11, a utility may comply with the Acid Rain NO_X emission limitations by averaging the emissions of units that the utility owns or operates in the same State or other States. Many utilities have complied, or plan to comply, with the Acid Rain NO_X Emission Reduction Program by using averaging plans, including some interstate averaging plans. However, a unit that has no Acid Rain emission limitation obviously cannot be included in an averaging plan since EPA would have no authority under title IV to limit the unit's emissions, whether on an individual-unit or a group-average basis. Further, as a practical matter, the group average limit for any given year, which must be calculated based on the limit applicable to each individual unit in the averaging plan, could not reflect any limit for such a unit. *See* 40 CFR 76.11(a) (1) and (2) (allowing only units with Acid Rain NO_X emission limitations in effect to participate in an averaging plan) and (d)(1)(ii)(A) (showing calculation of the group average limit using each unit's Acid Rain NO_X emission limitation).

In the proposal, EPA attempted to address the issue of the potential impact of proposed § 76.16 on averaging plans. Proposed § 76.16(b)(1)(ii) required that, in determining whether a NO_X cap-and-trade program met the requirements for granting units relief from the Phase II NO_X emission limitations, the Administrator must consider ''whether the cost savings from trading will be offset by elimination of the ability of an owner or operator of a unit in the State or the group of States to use a NO_X averaging plan under § 76.11.'' 63 FR 25974. However, commenters were still concerned that the Administrator could, even after taking this into consideration, grant the relief over a utility's objections and prevent the utility from using an averaging plan that included the units for which the Administrator made the Phase II NO_X emission limitations inapplicable. In light of the utilities' concerns that proposed § 76.16 would actually reduce utilities' compliance flexibility, albeit under title IV, and prevent the use of averaging plans authorized under section 407(e), EPA has decided *not* to revise part 76 as proposed and is *not* adopting proposed § 76.16 as a final rule.

Suggestions by some commenters that, instead of adopting proposed § 76.16, EPA extend the compliance date under the Acid Rain Program for the Phase II NO_X emission limitations are rejected as outside the scope of this rulemaking. As acknowledged by commenters, that issue was raised in the rulemaking adopting the Phase II NO_X emission limitations, and the compliance deadline of January 1, 2000 set in that rulemaking was recently upheld by the courts in *Appalachian Power* v. *EPA,* 135 F.3d 791 (D.C. Cir. 1998). The SIP call rulemaking did not include any proposal to alter that date. On the contrary, EPA stated in the SIP call:

Obviously, in proposing a new 40 CFR 76.16, EPA is not requesting comment on any aspect of the December 19, 1996 final rule [i.e., the rule that set the Phase II NO_X emission limitations and that included an earlier, proposed version of § 76.16], including any issues addressed by the Court in *Appalachian Power.* 63 FR 25951.

Similarly, commenters' suggestions concerning other revisions to the Acid Rain NO_X Emission Reduction Program regulations (e.g., revisions to change the averaging provisions in the Acid Rain regulations to allow averaging among units that lack common owners or operators) are rejected as outside the scope of this rulemaking.

IX. Non-Ozone Benefits of NO_X Emissions Decreases

A. Summary of Comments

One commenter suggested that drinking water nitrate is not affected by atmospheric emissions and that the impacts of eutrophication are unknown, although no evidence was presented. Another commenter stated that EPA should estimate in the RIA the benefits of the SIP call with respect to the non- ozone impacts. One comment was received stating that EPA should not consider non-ozone benefits as

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justification for the proposed emission reductions.

B. Response to Comments and Conclusion

1. Drinking Water Nitrate

There is no disagreement that high levels of nitrate in drinking water is a health hazard, especially for infants. The contribution of atmospheric nitrogen (N) deposition to elevated levels of nitrate in drinking water supplies can be described as an evolving impact area. The Ecological Society of America has included discussion of this impact in a recent major review of causes and consequences of human alteration of the global N cycle in its Issues in Ecology series (Vitousek, Peter M., John Aber, Robert W. Howarth, Gene E. Likens, et al. 1997. Human Alteration of the Global Nitrogen Cycle: Causes and Consequences. Issues in Ecology. Published by Ecological Society of America, Number 1, Spring 1997). For decades, N concentrations in major rivers and drinking water supplies have been monitored in the United States, Europe, and other developed regions of the world. Analysis of these data confirms a substantial rise of N levels in surface waters, which are highly correlated with human-generated inputs of N to their watersheds. These N inputs are dominated by fertilizers and atmospheric deposition.

Increases in atmospheric N deposition to sensitive forested watersheds approaching N saturation would be expected to result in increased nitrate concentrations in stream water. This phenomenon has been documented in the Los Angeles, California area and has been well-established for areas in Germany and the Netherlands (Riggan, P.J., R.N. Lockwood, and E.N. Lopez, ''Deposition and Processing of Airborne Nitrogen Pollutants in Mediterranean- Type Ecosystems of Southern California'' Environmental Science and Technology, vol. 19, 1985). Stream water nitrate concentrations in watersheds subject to chronic air pollution in the Los Angeles area were two to three orders of magnitude greater than in chaparral regions outside the air basin.

2. Eutrophication

The EPA believes that the eutrophication problem associated with atmospheric nitrogen deposition is well established. The National Research Council recently identified eutrophication as the most serious pollution problem facing the estuarine waters of the United States (NRC, 1993). NO_X emissions contribute directly to the widespread accelerated eutrophication of United States coastal waters and estuaries. Atmospheric nitrogen deposition onto surface waters and deposition to watershed and subsequent transport into the tidal waters has been documented to contribute from 12 to 44 percent of the total nitrogen loadings to United States coastal water bodies. Nitrogen is the nutrient limiting growth of algae in most coastal waters and estuaries. Thus, addition of nitrogen results in accelerated algae and aquatic plant growth causing adverse ecological effects and economic impacts that range from nuisance algal blooms to oxygen depletion and fish kills.

3. Regulatory Impact Analysis

The EPA believes it is important to note the potential impacts of the rulemaking, including the substantial benefits to the environment of several non-ozone impacts. As described in the November 7 proposal, in addition to contributing to attainment of the ozone NAAQS, decreases of NO_X emissions will also likely help improve the environment in several important ways: (1) On a national scale, decreases in NO_X emissions will also decrease acid deposition, nitrates in drinking water, excessive nitrogen loadings to aquatic and terrestrial ecosystems, and ambient concentrations of nitrogen dioxide, particulate matter and toxics; and (2), on a global scale, decreases in NO_X emissions will, to some degree, reduce greenhouse gases and stratospheric ozone depletion. These benefits were also specifically recognized by OTAG, which in its July 8, 1997 final recommendations, stated that it ''recognizes that NO_X controls for ozone reductions purposes have collateral public health and environmental benefits, including reductions in acid deposition, eutrophication, nitrification, fine particle pollution, and regional haze.'' However, the benefits of some of these impacts are very difficult to estimate. Where possible, EPA provides estimates of the impacts of the rulemaking—both ozone and non-ozone—in the RIA.

4. Justification for Rulemaking

While EPA believes this information is important for the public to understand and, thus, needs to be described as part of the rulemaking and RIA, there should be no misunderstanding as to the legal basis for the rulemaking, which is described in Section I, Background, of this notice and does not depend on the non-ozone benefits. The non-ozone benefits did not affect the method in which EPA determined significant contribution nor the calculation of the emissions budgets.

X. Administrative Requirements

A. Executive Order 12866: Regulatory Impacts Analysis

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be a ''significant regulatory action'' within the meaning of the Executive Order. As a result, the final rulemaking was submitted to OMB for review, and EPA has prepared a Regulatory Impact Analysis (RIA) entitled ''Regulatory Impact Analysis for the Regional NO_X SIP Call (September 1998).''

This RIA assesses the costs, benefits, and economic impacts associated with potential State implementation strategies for complying with this rulemaking. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** Section of this preamble. The RIA is available in hard copy by contacting the EPA Library at the address under ''Availability of Related Information'' and in electronic form as discussed above under ''Availability of Related Information.''

The RIA attempts to simulate a possible set of State implementation strategies and estimates the costs and benefits associated with that set of

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strategies. The RIA concludes that the national annual cost of possible State actions to comply with the SIP call are approximately $1.7 billion (1990 dollars). The associated benefits, in terms of improvements in health, crop yields, visibility, and ecosystem protection, that EPA has quantified and monetized range from $1.1 billion to $4.2 billion. Due to practical analytical limitations, the EPA is not able to quantify and/or monetize all potential benefits of this action.

B. Regulatory Flexibility Act: Small Entity Impacts

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. No. 104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. *See, Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1170 (D.C. Cir. 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC,* 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

The NO_X SIP Call would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose which sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities.

For these reasons, EPA appropriately certified that the rule would not have a significant impact on a substantial number of small entities. Accordingly, the Agency did not prepare an initial RFA for the proposed rule.

For the final rule, EPA is confirming its initial certification. However, the Agency did conduct a more general analysis of the potential impact on small entities of possible State implementation strategies. This analysis is documented in the RIA. The EPA did receive comments regarding the impact on small entities. These comments will be addressed in the Response to Comment document.

This final rule will not have a significant impact on a substantial number of small entities because the rule does not establish requirements applicable to small entities. Therefore, I certify that this action will not have a significant impact on a substantial number of small entities.

C. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

The EPA has prepared a written statement consistent with the requirements of section 202 of the UMRA and placed that statement in the docket for this rulemaking. Furthermore, as EPA stated in the proposal, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, as described in the proposal, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA and Executive Order 12875, EPA carried out consultations with the governmental entities affected by this rule. Finally, the written statement placed in the docket also contains a discussion consistent with the requirements of section 205 of the UMRA.

For several reasons, however, EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. First, it is questionable whether a requirement to submit a SIP revision would constitute a federal mandate in any case. The obligation for a state to revise its SIP that arises out of sections 110(a) and 110(k)(5) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658 (a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

As noted earlier, however, notwithstanding these issues EPA has prepared the statement that would be required by UMRA if its statutory provisions applied and has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements. The analysis assumes that states would adopt the control strategies that EPA assumed in its analyses underlying this action. The EPA further notes that in two related proposals also signed today—one concerning federal implementation plans if States do not comply with the SIP call and one concerning the petitions submitted to the Agency under section 126 of the CAA—EPA is taking the position that the requirements of UMRA apply because both of those actions could result in the establishment of enforceable mandates directly applicable to sources (including sources owned by state and local governments).

D. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of

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Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1857.02) and a copy may be obtained from Sandy Farmer by mail at Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW., Washington, DC 20460, by email at farmer.sandy@epa.gov, or by calling (202) 260–2740. A copy may also be downloaded from the internet at http://www.epa.gov/icr. The information requirements are not effective until OMB approves them.

The EPA believes that it is essential that compliance with the regional control strategy be verified. Tracking emissions is the principal mechanism to ensure compliance with the budget and to assure the downwind affected States and EPA that the ozone transport problem is being mitigated. If tracking and periodic reports indicate that a State is not implementing all of its NO_X control measures beginning with the compliance date for NO_X controls or is off track to meet its statewide budget by September 30, 2007, EPA will work with the State to determine the reasons for noncompliance and what course of remedial action is needed.

The reporting requirements are mandatory and the legal authority for the reporting requirements resides in section 110(a) and 301(a) of the CAA. Emissions data being requested in today's rule is not be considered confidential by EPA. Certain process data may be identified as sensitive by a State and are then treated as ''State-sensitive'' by EPA.

The reporting and record keeping burden for this collection of information is described below:

Respondents/ Affected Entities: States, along with the District of Columbia, which are included in the NO_X SIP call.

Number of Respondents: 23.

Frequency of Response: annually, triennially.

Estimated Annual Hour Burden per Respondent: 269.

Estimated Annual Cost per Respondent: $7,140.00.

Estimated Total Annual Hour Burden: 6,197.

Estimated Total Annualized Cost: $164,190.00.

There are no additional capital or operating and maintenance costs for the States, along with the District of Columbia, associated with the reporting requirements of this rule. During the 1980s, an EPA initiative established electronic communication with each State environmental agency. This included a computer terminal for any States needing one in order to communicate with the EPA's national data base systems. Costs associated with replacing and maintaining these terminals, as well as storage of data files, have been accounted for in the ICR for the existing annual inventory reporting requirements (OMB # 2060–0088).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Office of Policy, Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW.; Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Comments are requested by November 27, 1998. Include the ICR number in any correspondence.

E. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

1. Applicability of E.O. 13045

The Executive Order 13045 applies to any rule that EPA determines (1) ''economically significant'' as defined under Executive Order 12866, and (2) the environmental health or safety risk addressed by the rule has a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children; and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is not subject to E.O. 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

2. Children's Health Protection

In accordance with section 5(501), the Agency has evaluated the environmental health or safety effects of the rule on children, and found that the rule does not separately address any age groups. However, the Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels experienced by children as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected 2007 ozone and PM concentrations. The population includes a census-derived subdivision for the under 18 group.

F. Executive Order 12898: Environmental Justice

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels that may be experienced by minority and low-income populations as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected ozone concentrations and PM concentrations. The population includes census-derived subdivisions for whites and non-whites, and for low-income groups.

G. Executive Order 12875: Enhancing the Intergovernmental Partnerships

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal

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government provides the funds necessary to pay the direct compliance costs incurred by those governments. If the mandate is unfunded, EPA must provide to the Office of Management and Budget a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments ''to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.''

Today's rule does not create a mandate on State, local or tribal governments. As explained in the discussion of UMRA (Section X.C), this rule does not impose an enforceable duty on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this rule.

H. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments. If the mandate is unfunded, EPA must provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. The rule applies only to certain States, and does not require Indian tribal governments to take any action. Moreover, EPA does not, by today's rule, call on States to regulate NO_X sources located on tribal lands. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

The only circumstance in which the rule might even indirectly affect sources on tribal lands would be if the budget set for one or more of the 23 jurisdictions reflects assumed emissions reductions from NO_X sources on tribal lands located within the exterior boundaries of those States. The EPA is not aware of any such sources. However, to address the possibility that one or more of the State budgets reflects reductions from such sources, and because any such State generally would not have jurisdiction over such sources (see EPA's rule promulgated under CAA section 301(d), 63 FR 7254, February 12, 1998), EPA will consider any request to revise as appropriate the budget and base year 2007 emissions inventory for such a State, based on a demonstration that the State does not have authority to regulate those sources.

I. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This Section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

Any final action related to the NO_X SIP call is ''nationally applicable'' within the meaning of section 307(b)(1). As an initial matter, through this rule, EPA interprets section 110 of the CAA in a way that could affect future actions regulating the transport of pollutants. In addition, the NO_X SIP call, as proposed, would require 22 States and the District of Columbia to decrease emissions of NO_X. The NO_X SIP call also is based on a common core of factual findings and analyses concerning the transport of ozone and its precursors between the different States subject to the NO_X SIP call. Finally, EPA has established uniform approvability criteria that would be applied to all States subject to the NO_X SIP call. For these reasons, the Administrator also is determining that any final action regarding the NO_X SIP call is of nationwide scope and effect for purposes of section 307(b)(1). Thus, any petitions for review of final actions regarding the NO_X SIP call must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A ''major rule'' cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. § 804(2). This rule will be effective December 28, 1998.

K. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Pub. L. No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking sets forth a model trading program including environmental monitoring and measurement provisions that States are encouraged to adopt as part of their SIPs. If States adopt those provisions, sources that participate in the trading program would be required to meet the applicable monitoring requirements of part 75. In addition, this final rulemaking requires States that choose to regulate certain large stationary sources to meet the requirements of the SIP call to use part 75 to ensure compliance with their regulations. Part 75 already incorporates a number of voluntary consensus standards. In addition, EPA's proposed revisions to part 75 proposed to add two more voluntary consensus standards to the rule (see 63 FR at 28116–17, discussing ASTM D5373–93 ''Standard Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke,'' and API Section 2 ''Conventional Pipe Provers'' from Chapter 4 of the Manual for Petroleum Measurement Standards, October 1988 edition). The EPA's proposed revisions to part 75 also requested comments on the inclusion of additional voluntary consensus standards. The EPA is finalizing some revisions to part 75 now, including the incorporation of two voluntary consensus standards, in response to comments submitted on the proposed part 75 rulemaking:

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19 and,

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed October 1992), for § 75.19.

These materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

These standards are used to quantify fuel use from units that have low emissions of NO_X and SO_X.

The EPA intends to finalize other revisions to part 75 in the near future and address comments related to the proposed voluntary consensus standards and to additional voluntary consensus standards at that time.

Consistent with the Agency's Performance Based Measurement System, part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. The EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified, however any alternative methods must be approved in advance before they may be used under part 75.

List of Subjects

40 CFR Part 51

Air pollution control, Administrative practice and procedure, Carbon monoxide, Environmental protection, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Transportation, Volatile organic compounds.

40 CFR Parts 72 and 75

Air pollution control, Carbon dioxide, Continuous emissions monitors, Electric utilities, Environmental protection, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 96

Environmental protection, Administrative practice and procedure, Air pollution control, Nitrogen dioxide, Reporting and recordkeeping requirements.

Dated: September 24, 1998.

Carol M. Browner,

Administrator.

Appendix A to the Preamble—Detailed Discussion of Changes to Part 75

The following discussion addresses the comments received both on the SNPR (68 FR 25902) and the proposed part 75 revisions (68 FR 28032) that relate to the monitoring of NO_X mass emissions. In addition, it addresses the comments received on the excepted monitoring methodology for low mass emitting units that would apply to both units affected by title IV of the CAA and to units affected by a State or Federal NO_X mass reduction program that adopted or incorporated the requirements of this part.

I. NO_X Mass Monitoring and Reporting Provisions

Commenters raised four main issues with the proposed NO_X mass monitoring and reporting provisions in subpart H. The first issue has to do with the appropriate monitoring requirements necessary to support a NO_X mass monitoring program, particularly in light of the fact that many of the units that would be subject to a program based on Part 96 are not currently monitoring NO_X mass emissions. The second has to do with using a NO_X concentration CEMS and a flow CEMS to calculate NO_X mass. The third has to do with the requirement to report NO_X mass emissions year round even though the ozone season is only 5 months long. The final issue has to do with the requirement to have petitions for alternatives to part 75 be approved by both the state permitting authority and by EPA.

A. Background on Use of Part 75 to Monitor and Report NO_X Mass Emissions

Subpart H of the proposed part 75 rule set forth general monitoring and reporting requirements that sources subject to a State or Federal NO_X mass emission reduction program could incorporate or adopt into that program. Several commenters argued that it was inappropriate to require sources, who were not already required to meet the requirements of part 75, to meet those requirements for purposes of a state program.

Commenters who suggested that it was inappropriate to require a source that is not already subject to part 75 to meet the requirements of part 75 for purposes of a state program suggested that the State should decide what requirements the source needs to meet. The EPA agrees that this would be appropriate in the case of a program that only affected that state. For instance, if a State was developing a NO_X reduction program to address its own non-attainment problem, it would not be necessary to adopt requirements that were consistent across a larger geographic area. However, in a multi-state program, particularly a multi-state trading program which engages in interstate commerce like the one set forth in part 96, EPA believes it is necessary to account for emissions in a consistent manner across the whole region. This ensures that all sources that participate in the trading program account for their emissions in a consistent manner, ensuring both integrity in the trading program and a level playing field for all program participants. Therefore, EPA believes that it is necessary to create one set of consistent monitoring and reporting requirements that can be used for such a program. This is consistent with the way the Act mandated that a multi-state trading program be implemented under Title IV. It is also consistent with the

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approach taken in implementing other emissions standards, such as the new source performance standards that affect many states. This approach also makes it easier for states designing their programs since they would not have to reinvent the monitoring requirements in each case.

Commenters who suggested that part 75 did not provide enough flexibility focused on three areas: they suggested that other programs such as RECLAIM or the OTC trading program provided more flexible non-CEMS options for units that operated infrequently or had low NO_X mass emissions; they suggested that sources should be allowed to use predictive emissions monitoring systems (PEMS); and they suggested that sources should be allowed to use coal sampling and weighting to determine heat input.

The EPA believes that the flexibilities offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that emit more than 10 tons of any individual pollutant per year. The OTC Program requires CEMS on all units that do not qualify as peaking units that are larger than 250 mmBtu or serve generators greater than 25 MWs. Subpart H of part 75 allows non-CEMS alternatives for units that have emissions less than 50 tons per year of NO_X. If a unit is not required to report SO_2 and CO_2 for Acid Rain compliance, then the unit may use the low mass emissions provisions of Part 75 if its NO_X emissions are less than 50 tons per year. Part 75 also allows non-CEMS alternatives for units that qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year. The EPA believes that these options provide cost effective monitoring methodologies for small or infrequently used units.

While commenters who supported the use of PEMS and the use of coal sampling and weighting asserted that these methodologies would provide data equivalent to that provided by the methodologies in Part 75, none of the commenters provided any data to justify this claim. Therefore EPA is not adding specific requirements that would allow either of these methodologies. It should be noted that subpart E of part 75 does provide a means for a source to demonstrate that an alternative methodology such as PEMS or coal sampling and weighting is equivalent to CEMS. Subpart E of part 75 is consistent with Performance Based Measurement Systems criteria. Any source wishing to use an alterative methodology may petition the agency under subpart E of part 75.

B. Background on Use of a NO_X Concentration CEMS and a Flow CEMS to Calculate NO_X Mass

Subpart H of the proposed part 75 rule called for sources in the NO_X Budget Program to monitor NO_X emission rate in lb/mmBtu using a NO_X concentration monitor and a diluent monitor, and then to multiply this by heat input, calculated using a flow monitor and a diluent monitor. Under this proposal, sources would then calculate NO_X mass emissions by multiplying the hourly NO_X emission rate by the hourly heat input to obtain the pounds of NO_X emitted during the hour. The EPA also requested comment on whether it would be appropriate for sources in the NO_X Budget Program to use the NO_X concentration monitor and flow monitor without a diluent monitor to calculate NO_X mass emissions. This is analogous to the Acid Rain Program's current approach to monitoring SO_2 mass emissions.

Commenters recommended that the Agency require sources to determine NO_X mass emissions from pollutant concentration and stack gas volumetric flow. The commenters stated that this approach would be more accurate, more familiar to sources, and more consistent with the SO_2 mass emissions monitoring in the existing part 75.

The Agency agrees that using NO_X pollutant concentration and volumetric flow is an appropriate method for monitoring NO_X mass emissions. Today's final rule includes provisions in Subpart H and Section 8 of Appendix F of part 75 to allow sources to choose one of several options for monitoring and calculating NO_X mass emissions. Sources may monitor NO_X mass emissions by using either:

All Units

- A NO_X pollutant concentration monitor and a volumetric flow monitor, or a NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a flow monitor and a diluent monitor to calculate heat input; or
- A NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or

Oil/Natural Gas Fired Units

- Peaking units may use NO_X to load correlation procedures from Appendix E of part 75 for NO_X emission rate, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or
- Units with less than 50 tons of Nox and 25 tons of SO_2 may use emission rates multiplied by either the maximum rated heat input capacity of the unit or by the actual heat input of the unit which may be determined on a longer term basis than a single hour.

The EPA decided to allow sources several options so that they could use monitoring equipment that is already installed under part 75 to the greatest extent possible.

In implementing these options, a source would need to designate a primary approach to calculating NO_X mass emissions. For example, the designated representative of a coal-fired unit could choose to designate a primary monitoring approach under Option 1 (pollutant concentration monitor and diluent monitor, and diluent monitor and flow monitor). The designated representative could then use a (pollutant concentration monitor and flow monitor) as a backup monitoring approach. This would be useful for periods when the diluent monitor is not operating properly, where NO_X emission rate data in lb/mmBtu would not be available, but NO_X mass emission data in lb could still be available. The OTC NO_X Budget Program allows this approach (see docket A–97–35 item II-I–7).

In order to make monitoring as consistent as possible between the first two approaches for monitoring NO_X mass emissions using continuous emission monitoring systems (CEMS), EPA is making additional changes to part 75. First, the Agency is adding language in Section 8 of Appendix F that specifies the calculations for NO_X mass emissions using either approach. Second, EPA is requiring sources that use a NO_X pollutant concentration monitor and a flow monitor as the primary method for calculating NO_X mass emissions to substitute for missing NO_X pollutant concentration data using the same missing data procedures as for NO_X CEMS (lb/mmBtu) under §§ 75.31(c), 75.33(c) and Appendix C. Third, the Agency is establishing a relative accuracy testing requirement for NO_X pollutant concentration monitors that are used to calculate NO_X mass emissions independently of a NO_X CEMS (lb/mmBtu). The NO_X pollutant concentration monitors will need to meet a relative accuracy of 10.0 percent to pass the relative accuracy test audit (RATA). They will need to meet a relative accuracy of 7.5 percent to perform a RATA on an annual basis instead of a semi-annual basis. Because the vast majority of NO_X CEMS (lb/

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mmBtu) and SO_2 pollutant concentration monitors routinely meet a relative accuracy of 7.5 percent or less, the Agency concludes that it will also be possible for a NO_X pollutant concentration monitor, which is part of a NO_X CEMS, to meet this standard. Fourth, EPA requires these sources to test their NO_X pollutant concentration monitor and flow monitor for bias. If the monitor is found to be biased low, then the source must either fix the monitor and retest it to show it is not biased, or apply a bias adjustment factor to hourly data. These changes to part 75 make monitoring consistent between the different monitoring approaches using CEMS, prevent underestimation of emissions, preserve monitoring accuracy, and take advantage of approaches already developed for other monitoring systems that will be familiar to sources.

The EPA decided to allow sources to calculate NO_X mass emissions using NO_X concentration and flow rate for several reasons:

- This approach would allow sources to remove bias due to the diluent monitor from calculations of NO_X mass emissions.
- Sources affected by the NO_X Budget Program, but not by the Acid Rain Program, such as industrial boilers, may be able to simplify their recordkeeping and reporting because they will not need to calculate or report NO_X emission rate in lb/mmBtu for each hour for the trading program.
- Sources will be able to maintain higher availability of quality-assured NO_X mass emission data, because they will not need to substitute missing data for purposes of NO_X mass emissions when data are not available from the diluent monitor.
- As the commenters suggested, this approach is more analogous to monitoring for SO_2 mass emissions in the Acid Rain Program.

Because this approach is already allowed under the OTC NO_X Budget Program, EPA already has accounted for this possibility in the electronic data reporting format and in its computerized Emission Tracking System.

For these reasons, the Agency believes that it is appropriate to allow sources the option of monitoring and calculating NO_X mass emissions using NO_X pollutant concentration and flow monitors.

Sources using this approach may still be required to install maintain and operate a diluent monitor to calculate heat input if required to do so by their state for purposes of obtaining data needed to support allocation of NO_X allowances.

C. Background on Year Round Reporting of NO_X Mass Emissions

The proposal would have required all units to report NO_X mass emissions on an annual basis rather than on an ozone season basis. One commenter noted that since the proposed SIP call would not require emission reductions outside of the ozone season it is not necessary to report NO_X mass emissions outside of the ozone season. The EPA agrees that solely for the purposes of an ozone program, it may not be necessary to report NO_X mass emissions outside of the ozone season except if a source wants to qualify for the low mass emissions provision. However the requirements of subpart H could be used to support NO_X mass emission reduction programs where reductions would be required annually. In addition, the monitoring and reporting requirements could be used to help consolidate other State or Federal reporting that would be required on an annual basis. Therefore in the final rule the requirements of subpart H have been modified so that they no longer require annual reporting of NO_X mass emissions, but rather defer to the State or Federal rule that is incorporating these requirements to define the applicable time period for reporting.

In addition a new section has been added to subpart H that details how the requirements of part 75, which are designed to be used annually, should be used if monitoring and reporting is being done for only part of the year.

Some of the most significant differences include:

- Owners and operators of units using the fuel sampling procedures in Appendix D must ensure that they have accurate fuel sampling information at the beginning of the ozone season. This requires either sampling the fuel tank itself before the start of the ozone season or meeting the requirements to sample fuel deliveries on a year round basis.
- Historical lookback periods for missing data periods only need to include data from the ozone season. However, if a monitor is out of control at the beginning of the season, historical data from seven months ago may represent significantly different operating conditions (e.g. fuel burned or use of control equipment). Therefore the AAR would have to certify that the operating conditions are representative of the previous years operating conditions. If the conditions are not representative, the standard missing data procedures could not be used. In this case maximum potential NO_X mass emissions would have to be substituted.
- The owner or operator of a unit must ensure that the monitors used for monitoring and reporting are in control. Since CEMS require ongoing quality assurance to ensure that they are operating properly, owners and operators of units that do not meet this requirement during the non-ozone season will have to recertify their monitors before the start of the ozone season.

D. Background on Requiring EPA and the State Permitting Authority to Approve Alternatives to Part 75

The proposal would have required owners and operators of units that are not subject to the requirements of title IV of the CAA that wish to petition for an alternative to any of the requirements of part 75 to petition both the state permitting authority and the Administrator. Several commenters suggested that approval of one or the other should suffice. Some of the commenters also noted that the requirements were different for units affected by title IV, who are only required to petition the Administrator.

The EPA agrees that the requirements for units affected by title IV and units not affected by title IV are inconsistent. Because of different requirements of the Act this inconsistency is necessary. The EPA has the sole authority to grant petitions to units affected by title IV under § 75.66 of part 75. If a State incorporates those monitoring requirements into its State rules, this still does not give it the authority to change or waive the monitoring requirements for a unit subject to title IV. However, recognizing that granting a petition affects the accounting of NO_X mass emissions for a State program, EPA does intend to work cooperatively with State agencies on petition requests that could affect monitoring and reporting of NO_X mass emissions.

For sources not affected by title IV that are complying with the requirements of subpart H because they have been adopted or incorporated into a State SIP, neither EPA nor the State has sole authority to approve a petition for an alternative. While the State does have the authority to set forth specific monitoring and reporting requirements in a SIP and submit those requirements for EPA approval, a State does not have the discretion to modify the SIP by changing or waiving those monitoring and reporting requirements without obtaining EPA approval. Likewise, EPA does not have sole authority to revise a SIP since the primary responsibility to develop and implement a SIP is granted

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to the States under the CAA. The EPA is however required by the CAA to review and approve or disapprove SIP revisions. Since a petition to change or waive unspecified requirements related to monitoring and reporting can not be approved as part of the original SIP approval process, EPA must be involved in any approvals of alternatives to the SIP.

In addition to the title I requirements for EPA to be involved in approval of petitions for alternatives to part 75, there are several other reasons that EPA needs to be involved. The first is that since EPA is administering the emissions data collection system under part 75, EPA must ensure that any changes to the reporting requirements can be handled by the emissions tracking system that EPA maintains. Secondly, in order to ensure the integrity of a multi-state market based system and to ensure that participants in the system are treated equitably, it is important to ensure that sources are treated equitably from State to State. Therefore, if interstate trading is taking place EPA clearly has a role in approving petitions for alternatives to ensure that sources are treated consistently from state to state when engaging in such interstate commerce.

II. Low Mass Emissions Excepted Monitoring Methodology

A. Background

In the January 11, 1993 Acid Rain permitting rule, EPA provided for a conditional exemption from the emissions reduction, permitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions (see 58 FR 3593–94 and 3645–46). Moreover, in the January 11, 1993 monitoring rule, EPA allowed gas- fired and oil-fired peaking units to use the provisions of Appendix E, instead of CEMS, to determine the NO_X emission rate, stating that this was a *de minimis* exception. The EPA allowed this exception from the requirements of section 412 of the CAA because the NO_X emissions from these units would be extremely low, both collectively and individually (see 58 FR 3644–45). One utility wrote to the Agency, suggesting that the Agency consider further regulatory relief for other units with extremely low emissions that do not fall under the categories of small new units burning fuels with a sulfur content less than or equal to 0.05 percent by weight or gas-fired and oil-fired peaking units (see Docket A–97–35, Item II–D–31). The utility specifically suggested that the Agency consider an exemption, the ability to use Appendix E, or some other simplified methods which are more cost effective.

In the process of implementing part 75, other utilities also have suggested to EPA that it provide regulatory relief to low mass emitting units (see Docket A–97–35, Items II–D–29, II–E–25). These units might be low mass emitting because they use a clean fuel, such as natural gas, and/or because they operate relatively infrequently. Some utilities stated that they spend a great deal of time reviewing the emissions data when preparing quarterly reports for these units. Others argued that it would be important to reduce monitoring and quality assurance (QA) requirements in order to save time and money currently devoted to units with minimal emissions (see Docket A–97–35, Item II– E–25).

In response to the requests for simplified monitoring and recordkeeping requirements for units which both operate infrequently and have low mass emissions on May 21, 1998 the Agency proposed, under § 75.19 of part 75, changes to the monitoring requirements that would allow a new excepted methodology for low mass emission units. The proposed low mass emissions methodology would have allowed units which have emissions less than 25 tons of both NO_X and SO_2 to use a methodology with reduced monitoring, reporting and quality assurance requirements than the use of CEMS or either appendix D or E methodologies. The methodology proposed used a unit's maximum rated hourly heat input and generic defaults for SO_2, NO_X and CO_2 mass emissions. The proposed methodology was a less accurate methodology for determining emissions for SO_2, NO_X and CO_2 but would significantly reduce the burden on industry for these sources. The allowance of this methodology was justified using the *de minimis* individual and aggregate emissions represented by the units who would qualify for the methodology.

While the proposed methodology did not contain an explicit cutoff for CO_2, EPA believes that the limited applicability of the proposal ensured that emissions of CO_2 from units that would qualify to use the proposal was also *de minimis*. This is important, because under section 821 of the Act, the agency is also required to collect CO_2 emissions data from sources subject to title IV. This data is required to be collected ''in the same manner and to the same extent'' as required under title IV.

The Agency solicited comments on both the proposed methodology for determining emissions and the proposed applicability limits of 25 tons for both NO_X and SO_2 as well as any other comments related to the proposed low mass emission methodology. In reviewing the comments submitted on the proposal, the Agency noted that several commenters suggested the methodology was too restrictive and would only allow reduced monitoring to a limited number of units. The commenters suggested various methods for expanding applicability to the low mass emission methodology the most common which are; (i) remove the requirement for units to have both SO_2 and NO_X emissions of less than 25 tons and instead to allow units to use the methodology on a pollutant specific basis; (ii) increase the 25 ton limit for NO_X and SO_2 to 50, 100 or 250 tons; (iii) allow additional methods for calculating heat input; and (iv) allow the use of unit-specific NO_X emission rates. One other significant comment was received which indicated that the default values for NO_X emission rate in table 1b of proposed § 75.19 (c) could significantly underestimate emissions from certain types of units.

In response to the comments, which generally advocating the applicability of the low mass emissions methodology to more units, the Agency is adopting the proposed low mass emissions methodology with the following changes: (1) the NO_X applicability limit is being raised to 50 tons which will increase the number of units that can use the methodology; (2) units are being allowed an optional procedure for heat input which will increase the number of units that can use the methodology and provide more accurate emission estimates; (3) units are being allowed to use unit-specific NO_X emission rates determined through testing which will allow increased applicability and more accurate emissions estimates for NO_X; and (4) the values for NO_X emission rate in table 1b of proposed 75.19 (c) are being changed to prevent underestimation of emissions using the methodology.

B. Discussion of Low Mass Emissions Methodology

Today's new Low Mass Emissions methodology incorporates optional reduced monitoring, quality assurance, and reporting requirements into part 75 for units that burn only natural gas or fuel oil, emit no more than 25 tons of SO_2 and no more than 50 tons of NO_X annually, and have calculated annual

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SO_2 and NO_X emissions that do not exceed such limits. Units that are not subject to Title IV of the Act and that are only subject to subpart H of part 75 are not required to meet the SO_2 limit to qualify to use the methodology. In addition, if allowed by their State, they may qualify as low mass emission units during the ozone season if they emit less than 25 tons of NO_X per ozone season.

A unit may initially qualify for the reduced requirements by demonstrating to the Administrator's satisfaction that the unit meets the applicability criteria in § 75.19(a). Section 75.19(a) requires facilities to submit historical actual (or projections, as described below) and calculated emissions data from the previous three calendar years demonstrating that a unit falls below the 25-ton cutoff for SO_2 and the 50 ton cutoff for NO_X. The calculated SO_2 mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and the appropriate emission rate from table 1a in § 75.19(c). The calculated NO_X mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and either the appropriate emission rate from table 1b in § 75.19(c) or a unit-specific NO_X emission rate as allowed under § 75.19(c). The data demonstrating that a unit meets the applicability requirements of § 75.19(a) will be submitted in a certification application for approval by the Administrator to use the low mass emissions excepted methodology.

For units that lack historical data for one or more of the previous three calendar years (including new units that lack any historical data), § 75.19(a) will require the facility to provide (1) any historical emissions and operating data, beginning with the unit's first calendar year of commercial operation, that demonstrates that the unit falls under the 25-ton cutoffs for SO_2 and the 50 ton cutoff for NO_X, both with actual emissions and with calculated emissions using the proposed methodology, as described below; and (2) a demonstration satisfactory to the Administrator that the unit will continue to emit below the tonnage cutoffs (e.g., for a new unit, applying the applicable emission rates and applicable hourly heat input, under § 75.19(c), to a projection of annual operation and fuel usage to determine the projected mass emissions).

For units with historical actual (or projections, as described above) emissions and calculated emissions falling below the tonnage cutoffs, facilities allowed to use the optional methodology in § 75.19(c) in lieu of either CEMS or, where applicable, in lieu of the excepted methods under Appendix D, E, or G for the purpose of determining and reporting heat input, NO_X emission rate, and NO_X, SO_2, and CO_2 mass emissions. The facility will no longer be required to keep monitoring equipment installed on low mass emissions units, nor will it be required to meet the quality assurance test requirements or QA/QC program requirements of Appendix B to part 75. Moreover, emissions reporting requirements will be reduced by requiring only that the facility report the unit's hourly mass emissions of SO_2, CO_2, and NO_X, the fuel type(s) burned for each hour of operation, and report the quarterly total and year-to-date cumulative mass emissions, heat input, and operating time, in addition to the unit's quarterly average and year-to-date average NO_X emission rate for each quarter. Owners and operators may also choose to report partial hour operating time and use the operating time to obtain a more accurate estimate of heat input determined using the maximum hourly heat input option. For units which use the optional long term fuel flow methodology for heat input the source will report hourly and cumulative quarterly and yearly output in either megawatts electrical output or thousands of pounds of steam. For units which use unit-specific NO_X emission rates determined through testing, reporting of the Part 75 Appendix E test results will be required. For units that have NO_X controls, data demonstrating that these controls are operating properly will have to be kept on site. Facilities will continue to be required to monitor, record, and report opacity data for oil-fired units, as specified under §§ 75.14(a), 75.57(f), and 75.64(a)(iii) respectively. Under § 75.14(c) and (d), however, gas-fired, diesel-fired, and dual-fuel reciprocating engine units will continue to be exempt from opacity monitoring requirements.

If an initially qualified unit subsequently burns fuel other than natural gas or fuel oil, the unit will be disqualified from using the reduced requirements starting the first date on which the fuel (other than natural gas or fuel oil) burned.

In addition, if an initially qualified unit subsequently exceeds the 25-ton cutoff for either SO_2 or the 50 ton cutoff for NO_X while using the adopted methodology, the facility will no longer be allowed to use the reduced requirements in § 75.19(c) for determining the affected unit's heat input, NO_X emission rate, or SO_2, CO_2, and NO_X mass emissions (unless at a future time the unit can again meet the applicability requirements based on the recent three years of data). Adopted § 75.19(b) allows the facility two quarters from the end of the quarter in which the exceedance of the relevant ton cutoff(s) occurred to install, certify, and report SO_2, CO_2, and NO_X data from a monitoring system that meets the requirements of §§ 75.11, 75.12, and 75.13, respectively.

Under the low mass emission excepted methodologies in § 75.19(c), a facility will calculate and report hourly SO_2, NO_X and CO_2 mass emissions by multiplying hourly unit heat input by an appropriate emission rate. Unit heat input is determined using one of two heat input methodologies, maximum rated hourly heat input or long term fuel flow; unit SO_2 and CO_2 emission rates are determined using generic defaults; and unit NO_X emission rate is determined using one of two methodologies, generic defaults or unit-specific NO_X emission rate testing.

Commenters raised three major issues, which have led EPA to modify its proposal. The three major issues raised were: (i) Should the proposed initial and ongoing applicability criteria of 25 tons of both NO_X and SO_2 be modified; (ii) was the proposed methodology for estimating emissions appropriate and, should other options for calculating emissions be allowed; and (iii) what should the reduced monitoring and quality assurance requirements be for these units?

1. Applicability Criteria

a. Approach. Based on the rationale described in the preamble to the May 12, 1998 proposal (63 FR 28037) and in the absence of significant adverse comment, the Agency is using both actual and calculated emissions as the basis for determining initial applicability.

b. Cutoff Limit for Applicability. Several commenters requested that the cutoff limit for applicability of the low mass emission provision be increased. These comments fell into two broad categories: (1) decouple the NO_X and SO_2 requirements and allow units which qualify as a low mass emissions unit for only one pollutant to monitor that pollutant using the low mass emissions methodology (see Docket A–97–35, Items, IV–D–24, IV–D–11, IV–D–23, IV–G–03, IV–D–20); and (2) raise the tonnage cutoff for NO_X and SO_2 (see Docket A–97–35, Items, IV–G–03, IV–D–24, IV–D–22, IV–D–23, IV–D–07, IV–G–02).

c. Determining the Criteria for Low Mass Emitters. Based on comments received the Agency believes that the

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low mass emission provision is appropriate for units which have low mass emissions because: (i) a unit has a low capacity factor usage or operates infrequently; or (ii) a unit has low mass emissions despite a relatively high capacity factor due to the small size of the unit. For these units, the cost of installing and maintaining CEMS would represent a relatively large portion of the total value of the electricity or steam produced by the unit. The Agency, also reasoned that the types of units identified above can use the excepted methodology without any significant risk to the environment or impairment of the Agency's ability to meet its obligations under the CAA.

The Agency also determined the types of units which were not appropriate candidates for use of the low mass emissions excepted methodology. In particular, the Agency has concerns about allowing large numbers of controlled units to use an estimation methodology such as the low mass emission methodology. Because many of these units have low mass emissions not because they operate infrequently, but rather because they have controls which reduce their emission rates, their continued low mass emissions is dependent on continued proper operation of the controls on the unit. The EPA believes that monitoring actual emission rates is necessary to ensure that installed emission controls are operating properly and that actual emissions remain low. On the other hand, EPA believes that it is appropriate to allow small or infrequently operated units with controls, such as peaking turbines with water or fuel injection, to use the low mass emissions provision. This is appropriate because as long as these units continue to limit their operation, their potential to emit still remains low, even if their controls are not working. Therefore, while EPA believes it is appropriate to allow small infrequently operated units with controls that have both low actual emissions and a low potential to emit (as long as they continue to operate at low levels), EPA does not believe that it is appropriate to allow controlled units that have large potential to emit if their controls are not operating properly to use this methodology.

The low mass emission excepted methodology is a new exception, in addition to the exceptions in the existing rule, from the requirement for a NO_X CEMS. The determination of whether individual and collective emissions covered by the exceptions from CEMS are *de minimis* must include consideration of emissions from both new and existing units that will qualify to use the new low mass emissions excepted methodology and also new and existing units that will qualify to use other exceptions from the NO_X CEM requirement, i.e. units using the existing appendix E excepted methodology and units with new unit exemptions under § 72.7.

The EPA has first considered the level of projected aggregate emissions determined to be *de minimis* for purposes of developing the new unit exemption promulgated in the January 11, 1993 Acid Rain permitting rule (58 FR 3593–94 and 3645–46). Aggregate emissions projected for units under the exemption were approximately 138 cumulative tons of SO_2 and 1934 cumulative tons of NO_X emitted per year from an estimated 170 new units which might qualify for the exception before the year 2000. As of September of 1998, 278 exemptions have actually been granted under the new unit exemption. The Agency estimates that the level of SO_2 and NO_X mass emissions from these units is 226 tons of NO_X and 3163 tons of SO_2. The Agency further believes that this group of excepted units will continue to increase at the current rate.

The EPA has also considered the level of emissions projected to be covered by appendix E. The EPA, in the January 11, 1993 Acid Rain monitoring rule, allowed gas-fired and oil-fired peaking units to use the provisions of appendix E, instead of CEMS, to determine the NO_X emission rate. The Agency stated that, even though this method was less accurate than CEMS, this was a *de minimis* exception because emissions from all units that qualify to use the appendix E reporting methodology were projected to be extremely low, the units did not have a NO_X compliance obligation, and the cost of installing and operating CEMS for these units would be high (see 58 FR 3644–45). The preamble to the January 11, 1993 rule estimated the emissions from oil and gas units which operated with a capacity factor of less than 10 percent to be 40,000 tons of NO_X per year. The Agency has analyzed existing appendix E units to determine the actual NO_X mass emissions reported by these units in 1997. This analysis indicates that in 1997 approximately 235 units used the appendix E methodology and had total emissions of approximately 11,000 tons of NO_X in 1997. (see Docket A–97–35, Items, IV–A–1).

The Agency has then considered what level of total NO_X emissions would be *de minimis* for all units that may be covered by *de minimis* exceptions from the requirement to use CEMS i.e. all units using the new unit exemption, appendix E, and the new low mass emissions methodology. The Agency maintains that a *de minimis* level of total NO_X emissions should not be more than one percent of the total NO_X emission inventory currently or in the future for all units. This approach is supported by the treatment of 40,000 tons of NO_X as *de minimis* in the January 11, 1993 rule preamble concerning appendix E, which is somewhat less than 1 percent of the total NO_X emissions estimated for 1993. However, the 40,000 tons of NO_X determined to be *de minimis* emissions in 1993 is not an appropriate *de minimis* level with regard to current and future levels of NO_X emissions. Several factors have increased the importance of monitoring lower levels of NO_X emissions including: (i) The new more stringent NAAQS for ozone (NO_X is an ozone precursor); (ii) title IV Phase II NO_X reductions which will reduce the total NO_X inventory; (iii) today's NO_X SIP call which may result in NO_X compliance obligations for gas-and oil-fired units and will reduce the NO_X emission inventory; and (iv) State and regional NO_X reduction programs, such as the OTC program, State RACT rules and the RECLAIM program in California, which result in NO_X compliance obligations for gas-and oil- fired units and reduced NO_X emission inventory. As a result, EPA views about 20,000 tons (close to 1 percent of projected NO_X emission inventory) as the *de minimis* level of NO_X emissions for the present and foreseeable future.

Given that appendix E units and new unit exemption units currently account for about 14,100 tons of NO_X there is not a large margin left for establishing additional exception to the CEM requirements. The Agency has considered potential future growth in the number of units using the new unit exemption or appendix E in order to estimate what level of additional NO_X, SO_2 and CO_2 emissions might be appropriate to allow under the low mass emissions methodology. Taking account of the uncertainty inherent in such estimates EPA has set the applicability criteria for the low mass emission methodology so that the NO_X emissions covered by the methodology plus future growth in NO_X emissions covered by the other current *de minimis* exceptions (appendix E and the new unit exemption) will not exceed 5000 tons of NO_X per year in the future.

The Agency has analyzed SO_2, NO_X and CO_2 emissions and determined that, as long as the cutoffs for NO_X and SO_2 are coupled so that a unit must meet both the 50 tons of NO_X and 25 tons of

SO_2 limits, that SO_2, NO_X and CO_2 emissions under all exceptions from CEMS requirements will remain *de minimus*. Additionally decoupling the NO_X and SO_2 tons would allow only marginal simplification in monitoring while significantly complicating the low mass emissions methodology.

d Determining the Tonnage Cutoffs for SO_2 and NO_X. The Agency has conducted a study of actual emissions data from 1997 quarterly reports under part 75 and evaluated potential tonnage cutoffs for SO_X and NO_X (see Docket A–97–35, Item IV–A–1). The analysis was based on the assumption that reported 1997 emissions of NO_X and SO_2 will be more representative of calculated emissions under the final low mass emissions methodology than they would have been under the proposed methodology. The assumption is considered valid because the final low mass emissions methodology allows more accurate heat input determination using long term fuel flow and the use of fuel and unit specific NO_X emission rates. These options allow more accurate emissions estimates than the proposed methodology would have. This differs from the analysis performed for the proposed low mass emission methodology which calculated emissions based on operating hours and maximum rated heat input.

Based on this analysis, EPA estimates that the existing Acid Rain affected sources that would qualify for the low mass emissions excepted methodology using a coupled 50 tons NO_X and 25 tons SO_2 limit would represent aggregate emissions of approximately 3100 tons of NO_X and approximately 260 tons of SO_2 in 1997 from 224 units. The analysis indicates that the applicability has been substantially increased in response to the comments received.

For the proposed 25 ton NO_X cutoff , which is the limiting factor for applicability in nearly all instances, the Agency has considered increasing the tons of NO_X to 50 tons, 75 tons, 100 tons, and 250 tons as suggested by various commenters. In its analysis, the Agency kept SO_2 at 25 tons, as discussed above.

The analysis showed that by increasing the NO_X limit to 250 tons coupled to 25 tons of SO_2, the aggregate tons of NO_X and SO_2 emitted by units which could currently qualify for the low mass emissions methodology increased to approximately 23124 tons NO_X and 4503 tons of SO_2; this is without considering potential future growth in the number of units that could qualify to use this exemption. Increasing the cutoff for NO_X to 250 tons could also allow many units with highly effective NO_X controls to use the low mass emissions provision. As explained previously, units with effective NO_X controls and high operating capacity should not use the low mass emission provision. The EPA concludes that with a 250 ton NO_X mass emissions applicability cutoff, the aggregate NO_X tons and percentage of inventory potentially covered by all the exceptions encompassed would easily exceed the *de minimis* level of emissions. The EPA has therefore, not adopted an increased cutoff limit for NO_X of 250 tons. Similarly, EPA concludes that an increased cutoff of 100 tons of NO_X would not be consistent with the type of source which the Agency has identified for use of the low mass emission excepted methodology or fit under the *de minimis* level of emissions defined for NO_X by the Agency. At the 100 ton cutoff for NO_X coupled to a 25 ton cutoff for SO_2 the aggregate NO_X emissions are 8841 tons of NO_X and 540 tons of SO_2 from 408 qualifying units.

The analysis performed by the Agency indicates that 50 tons of NO_X coupled to 25 tons of SO_2 is the appropriate cutoff limit for applicability to the low mass emissions excepted methodology. The approximate aggregate emissions of 3600 tons of NO_X and 250 tons of SO_2 from 240 sources allows the appropriate type of units to use the provisions without great potential of exceeding a de-minimus level of NO_X emissions. In choosing the 50 ton NO_X mass emission cutoff limit over other limits, the Agency evaluated the available data and applied the following criteria: (1) The NO_X tons limit should allow reduced monitoring for the units which EPA determined were appropriate candidates for the low mass emissions provisions during the rulemaking process, namely units with low mass emissions both collectively and individually due to low operating levels or small size but not highly controlled units which operate at higher levels; (2) the NO_X tons limit should allow reduced monitoring for a group of units consistent with the level of *de minimis* emissions inventory for all exceptions for the CEMS requirement; and (3) the limit should not jeopardize the Agency's ability to effectively fulfill its obligations under of the CAA.

From the analysis performed, the Agency has demonstrated that increasing the 25 ton limit for SO_2 would result in allowing few additional sources the option to use the low mass emissions methodology. For example at a coupled 50 tons of NO_X and 25 tons of SO_2 increasing the SO_2 tonnage cutoff to 50 tons would allow only 7 additional units to use the methodology. The additional units identified all combusted oil as the primary fuel which has a very high sulfur content in comparison to natural gas. While natural gas fired units could easily increase operations without substantial increases in SO_2 emissions oil fired units could not. The additional units which burn oil and qualify are considered inappropriate candidates for use of the low mass emission provision. Therefore, the Agency has chosen to leave the tonnage limit at the proposed level of 25 tons for SO_2. Leaving the cutoff for applicability for SO_2 at 25 tons also reflected the opinion of commenters who suggested raising only the NO_X tonnage.

When considering the size cutoffs, EPA also took into account both the effect that the use of this methodology could have on other regulatory actions and the effect that other regulatory actions could have on the number of units and percentage of emissions that could be covered by units using this methodology. In particular, EPA was concerned about the SIP call. Units that could qualify to use the low mass emission methodology do not have a NO_X emission limit under title IV. However, under the SIP call, units that are using the monitoring requirements of part 75 to comply with the requirements of the SIP call, including units that could qualify to use the low mass emitter methodology, would have an emission limit. As explained in Section VI.A.2.c and VII.D.3 of today's preamble, EPA believes that it is important that large sources of NO_X mass emissions accurately account for their emissions. Because EPA is expecting substantial reductions in NO_X emissions from the title IV phase II NO_X emission rate limits, the SIP call and other similar programs, EPA believes that even if the total NO_X emissions coming from units that could qualify for the low mass emitter methodology does not increase, the percentage of emissions coming from these units will increase. The EPA also believes that the incentives provided under a trading program could encourage smaller oil and gas fired units that may not currently qualify under the low mass emission methodology to install controls. As a result, this could increase the number of units, the amount of emissions and the percentage of emissions that could be accounted for by units using this methodology. EPA believes that the 50 ton cutoff is adequate to ensure that emissions from units that qualify for the low mass

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emitter methodology are de-minimis today. In the future however, growth in the number of units may cause the level of NO_X, SO_2 or CO_2 emissions from units qualifying for and using the new unit exemption, appendix E, the low mass emitter provision and other programs such as the SIP call to exceed a de-minimis level and the agency reserves the right to re-assess any and all of these exceptions in the future if the need arises.

e. Decoupling NO_X and SO_2. In order to qualify for the low mass emissions excepted methodology, the applicability criteria require a unit to meet annual tonnage cutoffs of 25 tons for SO_2 and 50 tons for NO_X. The EPA has considered whether the excepted methodology should be available on a pollutant specific level so that, for example, a unit which falls below the tonnage cutoff for SO_2 but not for NO_X could use the excepted methodology under § 75.19 to measure SO_2 emissions but use a NO_X CEM or the excepted methodology under appendix E, where applicable, to measure NO_X emissions. All analysis the Agency has done indicates that the NO_X tonnage is the limiting factor for greater than 90 percent of all units when applicability is for units to meet a coupled 50 ton NO_X and 25 ton SO_2 limit (see Docket A–97–35, Items, II–A–10, IV–A–1) For example, approximately 20 units were identified which would potentially be qualified to use the low mass emission methodology for a 50 tons of NO_X cutoff who would not meet the 25 tons of SO_2 cutoff and therefore be disqualified from using the methodology. Conversely, the agency's analysis indicated that leaving the tonnage cutoff for SO_2 mass emissions at 25 tons and decoupling NO_X and SO_2 would potentially allow approximately 650 units in the program to use the low mass emissions methodology for SO_2 (see Docket A–97–35, Items, II–A–10, IV–A–1). In particular allowing decoupling could impair the Agency's ability to collect data on CO_2 emissions as required under the CAA section 821. The analysis performed by the Agency indicates, that even with a 25 ton limit on SO_2, 652 units could qualify for the use of the low mass emissions methodology for SO_2 only. The 652 units identified represent approximately 10 percent of the total program heat input and greater than 6 percent of the total program CO_2 emissions. If a unit which qualified for the use of only SO_2 were allowed to use the low mass emissions methodology for CO_2 the result could be overestimation of CO_2 emissions from a sizeable percentage of the total CO_2 inventory. Future decisions based on such data might draw incorrect conclusions.

For the reason stated above, if a unit were allowed to qualify for a single pollutant the unit would be allowed to use the low mass emissions methodology for that pollutant only and not for CO_2 or heat input estimations. Therefore, no practical benefit for industry would result from decoupling SO_2 and NO_X. Decoupling would not be particularly beneficial because qualifying for one pollutant only allows only minimal monitoring reductions when CO_2 and heat input are not simplified. In addition decoupling would dramatically increase the complexity of the low mass emissions methodology. The added complications which would benefit a limited number of sources in only a limited way would increase the time and effort needed for all other sources in understanding and implementing the methodology. The agency concludes that the burden from the increased rule complexity outweighs the benefit from decoupling SO_2 and NO_X.

The following discussions further explain the Agencies position.

One of the prime benefits of the low mass emissions excepted methodology will be the simplified reporting which will require less time and a less sophisticated Data Acquisition and Handling System (DAHS). In particular, the need for a DAHS that could calculate substitute data using the current missing data algorithms will be removed because there are no missing data algorithms for the low mass emissions excepted methodology. If the excepted methodology is only applied to one of the pollutants, much of the benefit would be negated because the DAHS will still need to be capable of calculating substitute data for the measured pollutant and close to the full quarterly report would still be required.

Another prime benefit of the low mass emissions excepted methodology will be the reduction of monitoring and quality assurance requirements. A unit which would qualify for SO_2 only would still need to determine CO_2 mass emissions using a fuel flow meter. Additionally the units which would qualify are primarily gas fired units which would be allowed to use appendix D for SO_2. In this case no benefit is allowed by using the low mass emissions methodology. A limited number of oil fired units would be granted some reduced sampling requirements.

The agency's analysis indicates that most units which would qualify for NO_X only can use the excepted methodology under appendix E.

As stated before the analysis indicates that the benefits of decoupling are outweighed by the complications of allowing decoupling.

f. The use of the Low Mass Emitter Methodology with fuels other than oil and natural gas. One commenter suggested that the applicability should be expanded to include other fuels including low sulfur solid fuels such as wood. EPA disagrees with the commenter who claims that the methodology should be irrespective of fuel type. The fuel type is an integral part of the emissions calculations and insures that emissions are not underestimated. The Agency does not have, and the commenter did not provide, sufficient data to justify including wood fired solid fuel units into the low mass emission methodology. The limited data EPA has does not provide assurance that wood is always low in sulfur or that it results in low mass emissions of NO_X. The use of AP 42 emission factors was considered but rejected based on the possibility of underestimation of NO_X emissions using the AP 42 factors, as stated in the January 11, 1993 rule preamble at 58 FR 364445. If EPA is provided with information addressing this issue in the future, EPA will consider expanding the applicability to units that burn wood in the future.

2. Method for Determining Emissions

On May 21, 1998 the Agency proposed a low mass emissions methodology which used maximum rated heat input as the only heat input option and default emission rates for SO_2, NO_X, and CO_2. The Agency requested comment on whether this methodology was appropriate or whether an alternate approach should be adopted for low mass emitting units. In response, several commenters suggested changing the method for determining emissions. One commenter suggested allowing the use of unit-specific NO_X testing (see Docket A–97–35, Item IV–D–20). Another commenter suggested that long term fuel flow heat input be allowed as an alternative to the proposed maximum rated heat input (see Docket A–97–35, Item IV–D–13). Two other commenters suggested that further unspecified options be allowed for determining heat input (see Docket A–97–35, Items, IV–D–03, IV–G–02). Additionally several commenters suggested that the reduced monitoring under the low mass emission methodology was being limited to too few sources (see Docket A–97–35, Items, IV–D–07, IV–D–22, IV–D–23, IV–D–24, IV–G–03). Other commenters made the general suggestion that part 75 should

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be more consistent with the monitoring requirements of the OTC NO_X Budget Program. Finally the Agency received both comments and data which indicated that for uncontrolled gas fired turbines combusting both oil and gas the default emission rates for NO_X in proposed table 1b of § 75.19 (c) were potentially substantial underestimations of actual emission from these types of units (see Docket A–97–35, Item IV–D–22). Further analysis by the Agency provided supporting evidence that the emission rates in proposed 75.19 (c), table 1b, might underestimate emissions significantly for gas and oil fired turbines (see Docket A–97–35, Item IV–A–1). In response to these comments which reflected a general desire to expand the applicability of the low mass emission methodology through changes in both the heat input and NO_X emissions methodology, and in light of no negative comments reflecting opposition to allowing the low mass emission methodology, the Agency began analysis of what changes in the methods for determining heat input and NO_X emissions could be allowed without risk of underestimation of emissions, or negative environmental consequences. The Agency received no comments on changing either the SO_2 or CO_2 methods for determining emissions and therefore did not attempt to change these methodologies.

a. Adoption of the Proposed Methodology. In the proposal, the Agency considered several methods for determining the estimated emissions as the basis for applicability of the reduced monitoring and reporting excepted methodology. For each of the methods considered, rather than using actual measured sulfur and carbon values, CO_2, SO_2, and flow CEM readings, NO_X CEM readings, or NO_X values from an Appendix E NO_X-versus-heat input correlation, a facility will calculate the unit's emissions based on an emission rate factor and one of two heat input methodologies. Since the units that will qualify for the excepted methodology will still be accountable for reporting emissions to the Agency and surrendering allowances based on those emissions, where applicable, the emissions estimations will not just be used to determine if the unit qualifies under the exception; the reported estimations will also be used to determine compliance. Prior to the proposal, some industry representatives suggested that facilities would be willing to use a conservative emission estimate, such as a maximum potential emission rate times the maximum heat input, if it would allow them to save time and money currently spent on monitoring and quality assurance (see Docket A–97–35, Items II–D–30, II–D–43, II–D–45, II–E–13, and II–E–25). The Agency decided it was appropriate to retain the proposed methodologies of maximum rated heat input and default SO_2, NO_X and CO_2 emission rates for the final rule. It was also decided to allow increased applicability of the low mass emissions methodology through optional unit-specific NO_X emission rate determinations and the use of an optional heat input methodology (e.g., long term fuel flow).

b. Change in Table 1b, Default NO_X Emission Rates. In deciding to retain the proposed low mass emission methodology as part of the final rule the Agency had to consider that some values for NO_X emission rate in proposed table 1b of § 75.19 (c) had a high potential for underestimating emissions in at least some cases. The Agency acknowledged that increasing the default NO_X emission rates in table 1b of § 75.19 (c) will reduce the number of units allowed to use the low mass emissions methodology. Based on the comments received (see Docket A–97–35, Item IV–D–20) and to both allow increased applicability and increase the default rates to an appropriate level, the use of NO_X testing to determine units-specific NO_X emission rates will be allowed as an alternative option to using the default NO_X emission rates in table 1b of § 75.19 (c). Allowing the option of unit-specific NO_X emission rates will generate more realistic NO_X emission rates than the default NO_X emission rates in table 1b of § 75.19 (c) and will maintain some of the simplicity of the NO_X mass methodology from the low mass emissions methodology proposal.

The next issue was deciding which default NO_X emission rates in table 1b of § 75.19 (c) to raise and what level to raise the defaults to. As a first consideration the Agency noted that the default NO_X emission rates in table 1b of proposed § 75.19 (c) should be increased to the level at which it will be highly unlikely that any unit that performed testing will have a higher emission rate than the default. In this case, a source might opt to use a default which would knowingly underestimate emissions under certain operating conditions. Since all of the defaults used in table 1b of proposed § 75.19 (c) were based on the 90th percentile it is very likely that some units would have a higher emission rate than the NO_X emission rates in table 1b of proposed 75.19 (c). For this reason, all of the NO_X emission rate values in proposed table 1b were increased to a level which will ensure that units will not have higher tested emission rates than the default rates in Table 1b. A commenter suggested that these provisions be more consistent with the provisions for the Ozone Transport Commission (OTC), NO_X Budget Program (see Docket A–97–35, Item IV–D–13). The default emission rates the Agency decided to adopt are the default rates used in the OTC NO_X Budget Program (see Docket A–97–35, Item II–I–7). In the OTC NO_X Budget Program, units similar in emission characteristics to those who will qualify as low mass emission units under today's rule have the option of unit specific testing or unit generic default OTC NO_X emission rates. In the OTC NO_X Budget Program units have chosen both options based on owner or operator preference. Finally, adopting the NO_X Budget Program defaults creates consistency among programs which is a supplementary benefit.

c. Unit-Specific NO_X Emission Rate Testing. In considering the options for unit-specific NO_X emission rate testing the Agency had to address several concerns, including the following: (1) Units with NO_X controls who performed unit specific testing with the controls operating might have the potential to grossly underestimate emissions if the controls failed; (2) what sort of test would be appropriate for determining the low mass emissions methodology fuel-and-unit-specific NO_X emission rate; (3) how long a period should a source be allowed to use the unit-specific NO_X rate once determined through testing; (4) under what conditions should a source be required to retest for a new unit-specific NO_X emission rate; (5) for sources with historical reported emissions data using CEMS under part 75, what historical NO_X emission rate value might be appropriate for use in lieu of an initial test; and (6) if a source owns multiple identical units, should representative testing be allowed at some of the units to represent all units.

The first issue resolved was the use of Appendix E of Part 75 procedures for determination of a unit-specific NO_X emission rate for each fuel combusted by the unit. The unit-specific NO_X emission rate selected, for each fuel tested, will be the highest recorded NO_X emission rate from the test at any test load or operating condition multiplied by 1.15. Units which combust multiple fuels can use, for different fuels, either a unit-specific NO_X rate determined through testing or use the default NO_X emission rates listed in table 1b of § 75.19 (c). For example, a unit which primarily combusts oil but occasionally combusts natural gas could determine a unit-specific NO_X emission rate for oil through Appendix E testing and use the default NO_X emission rate from table 1b of § 75.19 (c) for gas. For hours in which a unit combusts multiple fuels in one hour, the unit must use the highest emission rate for that hour for all fuels combusted. In conducting the Appendix E test, the requirement for monitoring heat input to the unit during the test is removed as it is an unnecessary burden. The multiplier of 1.15 is required because of Agency analysis which indicates that appendix E testing is not representative of emissions at a given load at all times. In particular, the analysis of units with NO_X emission rate CEMS indicated that the NO_X emission rate can vary an average of 15 percent at a given load during different periods of operation. The most probable cause of the difference noted is variations in atmospheric moisture content. The agency notes that units which do appendix E testing during hot humid conditions would likely underestimate emissions during cooler less humid conditions. The Appendix E test was chosen for several reasons including: (1) many current Acid Rain sources which might qualify for the low mass emissions methodology already have performed Appendix E testing and will be allowed to use their historical Appendix E test data to determine a unit-specific NO_X emission rate without further requirements; (2) the requirements of Appendix E testing are already familiar to sources and contractors who may perform the testing, thus reducing further burden imposed by requiring new testing methodologies; (3) The use of the Appendix E test and the multiplier of 1.15 ensures that a unit uses a NO_X emission rate which will not underestimate emissions at any normal operating condition.

Once the Appendix E test was chosen, the use of a five year testing frequency was deemed appropriate as it matched the current Appendix E test period and matches the current permit renewal cycle.

A special provision was included in the low mass emission methodology to allow units with historical CEMS NO_X emission rate data to determine a unit- specific NO_X emission rate from historical certified CEMS data. Under this provision a unit will analyze historical data from hours in which a unit combusted a particular fuel. The analysis will determine the unit-specific NO_X emission rate which will yield a 95 percent confidence that the unit will not emit at a higher NO_X emission rate while combusting the fuel being analyzed. The Agency also considered using the highest NO_X rate from historical data but reasoned that the large data sets used to generate the unit- and fuel-specific emission rate would contain outliers which would make the procedure unfeasible for most units. The Agency considered several options for units which used NO_X controls and wished to use unit-specific NO_X emission rates determined through Appendix E testing. One option was to allow units to test with the NO_X control devices not operating or minimized. This option was rejected for the following two reasons: (1) the Agency does not support adopting a rule which would require sources to operate in a manner that would increase emissions; and (2) some sources which have controls are not allowed to operate when the controls are not operating by permit restrictions and these units would be disallowed from using the low mass emission methodology unfairly. The Agency also considered not allowing units with NO_X emission controls to use the low mass emission methodology. While the Agency does believe that it is *not* appropriate to include large controlled units, the Agency does feel it is appropriate to allow infrequently used controlled units, such as peaking turbines with steam or water injection to benefit from the reduced requirements of this methodology (as further explained above). Therefore this solution was rejected as excluding many units for which the Agency believes it is appropriate to allow reduced monitoring from more accurate and more costly monitoring requirements.

The Agency also considered allowing only units with certain types of controls to use the low mass emission methodology. This approach was rejected because the Agency does not, at this time, have the necessary information or expertise to make an appropriate determination on this approach.

The Agency also considered allowing units to determine a unit-specific NO_X emission rate using NO_X controls with no restriction. In analyzing this option, the Agency identified several units which would qualify for the low mass emission methodology based on the applicability criteria of 50 tons of NO_X and 25 tons of SO_2 which the Agency did not believe were appropriate to use the low mass emission methodology. The units identified had advanced control technologies such as selective catalytic reduction (SCR) and burned low sulfur fuels such as natural gas. The units identified consistently reported hourly emission rates as low as 0.01 lb/mmBtu as compared to uncontrolled rates which are generally 10 to 100 times higher for these units. The best method of continued assurance that a unit's NO_X controls are operating is monitoring with a NO_X CEMS. These units also operated during more than half the hours of a year at an average heat input of greater than 1000 mmBtu/hr. While, for these units, the potential to underestimate SO_2 emissions was low, the potential to grossly underestimate NO_X mass emissions using the low mass emission methodology was much greater. For this reason, the Agency rejected allowing a controlled unit to use a single emission rate determined through Appendix E testing once every five years while NO_X controls were operating.

The methodology the Agency adopted in this rule was the use of a lower limit of 0.15 lb/mmBtu for a unit-specific NO_X emission rate for units which opt to perform unit-and fuel-specific Appendix E testing while controls are operating. For units with NO_X emission controls, which perform unit-specific NO_X emission rate testing and whose test results in a NO_X emission rate of less than 0.15 lb/mmBtu, the source will use the NO_X emission rate limit of 0.15 lb/mmBtu for the unit-specific NO_X emission rate instead of the lower tested NO_X emission rate. Units with NO_X emission controls who perform unit-specific NO_X emission rate testing and whose results from the testing indicate a NO_X emission rate of higher than 0.15 lb/mmBtu will be required to use the higher NO_X emission rate as the fuel- and unit-specific NO_X emission rate. In considering this approach the Agency considered using the lowest NO_X emission rate proposed in 75.19 (c), Table 1b, of 0.172 lb/mmBtu, as well as 0.15 lb/mmBtu, 0.1 lb/mmBtu and 0.05 lb/mmBtu as lower limits for NO_X emission rate. The proposed gas fired turbine emission rate was 0.172 lb/mmBtu. Using 0.172 lb/mmBtu as the lower limit for controlled units was rejected as being an arbitrary choice based on a number representative of only a single class of units and not representative of the difference between controlled and uncontrolled units. An analysis was performed to determine a reasonable lower cutoff between controlled and uncontrolled units which would allow controlled units to qualify for the reduced monitoring provisions of the excepted low mass emission methodology without serious risk of underestimation of emissions. The analysis indicated that a minimum allowable emission rate of 0.15 lb/mmBtu for controlled units best allowed for fairness between controlled and uncontrolled units and insured that very

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large units with high operating hours and extremely low NO_X emission rates will not be allowed to use the low mass emission excepted methodology. The Agency's decision was also heavily influenced by the desire to insure that overall, the emission rate chosen would insure that aggregate emissions of controlled units were indeed *de minimis.* The Agency notes that the lower limit of 0.15 lb/mmBtu NO_X emission rate, when coupled with the annual limit of 50 tons of NO_X, effectively limits the annual heat input of units using the methodology to 666,666 mmBtu annual heat input. Analysis done by EPA found this to be an appropriate limit on heat input for the low mass emission excepted methodology (see Docket A–97–35, Item IV–D–20). In general, the lower emission rate limit for controlled units, and uncontrolled units inability to achieve such low rates, combines to limit the low mass emission methodology to the infrequently operated low mass emitting units the Agency was targeting for use of the provision in today's new rule.

Controlled units that use this methodology are also subject to additional requirements. The owner or operator of the unit must ensure that the controls are being operated in the same manner that they were operated during the unit specific testing. Documentation of this must be kept on site. Any hour that the controls are not operating properly, the owner or operator must use the default emission rates for NO_X in table 1.b of § 75.19 (c), rather than the emission rate determined through unit specific testing.

Based on experience gained working with the OTC in the implementation of the OTC NO_X budget program, EPA believes that many of the units that may benefit from this new excepted monitoring methodology are banks of identical small emission turbines. The OTC has allowed these units to do representative sampling at a number of units rather than requiring testing at all of the units. While none of the commenters mentioned this specific flexibility of the OTC NO_X Budget program, EPA believes that this is one of the flexibilities that commenters who suggested adopting some of the methodologies that the OTC has allowed for smaller units were referring to. Therefore this final rule contains a similar allowance for identical units. If the owner or operator of a number of units that are located at one facility can demonstrate that those units are identical, this final rule will allow emission rate testing to be done at a representative number of units.

d. The Adoption of Maximum Rated Heat Input as Proposed. While several commenters suggested allowing alternative methods for determining heat input, none directly suggested replacing or altering the basic heat input approach as an option (as described in 68 FR 28037–8). For this reason the maximum rated hourly heat input option from the proposal was retained as a less accurate but acceptable approach.

e. Long Term Fuel Flow for Heat Input Determination. To allow greater flexibility to units under the low mass emissions methodology and to allow more realistic estimations of heat input as suggested by several commenters the Agency is allowing the use of long term fuel flow measurements to determine heat input to low mass emitting units as described earlier. The Agency chose to adopt this methodology for the following reasons: (1) The methodology allows more accurate measurements of total heat input into a unit over the reporting period than the use of maximum rated hourly heat input; (2) the methodology has proven to be usable by sources who have chosen to use a similar method in the Ozone Transport Commission, NO_X Budget Program; and (3) the methodology is straightforward and is optional for sources which might be excluded from using the low mass emissions methodology if allowed to use maximum rated hourly heat input only.

3. *Reduced Monitoring and Quality Assurance Requirements.* As discussed above, today's rule allows facilities to use a maximum rated hourly heat input value and an emission rate factor to determine the mass emissions from a low-emitting unit for each hour of actual operation. This approach involves no actual emissions monitoring and minimal quality assurance activities. Instead, the facility will only need to keep track of whether the unit combusted any fuel for a particular hour and what type of fuel was combusted. In this way, the revised rule significantly reduces the burden on affected facilities, while still ensuring that emissions are not under reported.

For owners or operators which opt to use either the long term fuel flow methodology or a fuel-and unit-specific NO_X emission rate, some additional quality assurance will be required. As these two options under the low mass emission methodology are not required and will allow units which would not otherwise qualify to use the low mass emission methodology, the additional quality assurance requirements are not burdensome to the sources using either long term fuel flow or unit-specific NO_X emission rates.

For the reasons set forth in the preamble, parts 51, 72, 75, and 96 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart G—Control Strategy

2. Subpart G is amended to add §§ 51.121 and 51.122 to read as follows:

§ 51.121 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen.

(a)(1) The Administrator finds that the State implementation plan (SIP) for each jurisdiction listed in paragraph (c) of this section is substantially inadequate to comply with the requirements of section 110(a)(2)(D)(i)(I) of the Clean Air Act (CAA), 42 U.S.C. 7410(a)(2)(D)(i)(I), because the SIP does not include adequate provisions to prohibit sources and other activities from emitting nitrogen oxides (''NO_X'') in amounts that will contribute significantly to nonattainment in one or more other States with respect to the 1-hour ozone national ambient air quality standards (NAAQS). Each of the jurisdictions listed in paragraph (c) of this section must submit to EPA a SIP revision that cures the inadequacy.

(2) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each jurisdiction listed in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I), 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8-hour ozone NAAQS.

(b)(1) For each jurisdiction listed in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision:

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(i) Contains control measures adequate to prohibit emissions of NO_X that would otherwise be projected, in accordance with paragraph (g) of this section, to cause the jurisdiction's overall NO_X emissions to be in excess of the budget for that jurisdiction described in paragraph (e) of this section (except as provided in paragraph (b)(2) of this section),

(ii) Requires full implementation of all such control measures by no later than May 1, 2003, and

(iii) Meets the other requirements of this section. The SIP revision's compliance with the requirement of paragraph (b)(1)(i) of this section shall be considered compliance with the jurisdiction's budget for purposes of this section.

(2) The requirements of paragraph (b)(1)(i) of this section shall be deemed satisfied, for the portion of the budget covered by an interstate trading program, if the SIP revision:

(i) Contains provisions for an interstate trading program that EPA determines will, in conjunction with interstate trading programs for one or more other jurisdictions, prohibit NO_X emissions in excess of the sum of the portion of the budgets covered by the trading programs for those jurisdictions; and

(ii) Conforms to the following criteria:

(A) Emissions reductions used to demonstrate compliance with the revision must occur during the ozone season.

(B) Emissions reductions occurring prior to the year 2003 may be used by a source to demonstrate compliance with the SIP revision for the 2003 and 2004 ozone seasons, provided the SIP's provisions regarding such use comply with the requirements of paragraph (e)(3) of this section.

(C) Emissions reduction credits or emissions allowances held by a source or other person following the 2003 ozone season or any ozone season thereafter that are not required to demonstrate compliance with the SIP for the relevant ozone season may be banked and used to demonstrate compliance with the SIP in a subsequent ozone season.

(D) Early reductions created according to the provisions in paragraph (b)(2)(ii)(B) of this section and used in the 2003 ozone season are not subject to the flow control provisions set forth in paragraph (b)(2)(ii)(E) of this section.

(E) Starting with the 2004 ozone season, the SIP shall include provisions to limit the use of banked emissions reduction credits or emissions allowances beyond a predetermined amount as calculated by one of the following approaches:

(1) Following the determination of compliance after each ozone season, if the total number of emissions reduction credits or banked allowances held by sources or other persons subject to the trading program exceeds 10 percent of the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program, then all banked allowances used for compliance for the following ozone season shall be subject to the following:

(i) A ratio will be established according to the following formula: $(0.10) \times$ (the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program) $\div$ (the total number of banked emissions reduction credits or emissions allowances held by all sources or other persons subject to the trading program).

(ii) The ratio, determined using the formula specified in paragraph (b)(2)(ii)(E)(1)(i) of this section, will be multiplied by the number of banked emissions reduction credits or emissions allowances held in each account at the time of compliance determination. The resulting product is the number of banked emissions reduction credits or emissions allowances in the account which can be used in the current year's ozone season at a rate of 1 credit or allowance for every 1 ton of emissions. The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of the resulting product either may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(2) At the time of compliance determination for each ozone season, if the total number of banked emissions reduction credits or emissions allowances held by a source subject to the trading program exceeds 10 percent of the source's allowable ozone season NO_X emissions, all banked emissions reduction credits or emissions allowances used for compliance in such ozone season by the source shall be subject to the following:

(i) The source may use an amount of banked emissions reduction credits or emissions allowances not greater than 10 percent of the source's allowable ozone season NO_X emissions for compliance at a rate of 1 credit or allowance for every 1 ton of emissions.

(ii) The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of 10 percent of the source's allowable ozone season NO_X emissions may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(c) The following jurisdictions (hereinafter referred to as ''States'') are subject to the requirements of this section: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, and the District of Columbia.

(d)(1) The SIP submissions required under paragraph (a) of this section must be submitted to EPA by no later than September 30, 1999.

(2) The State makes an official submission of its SIP revision to EPA only when:

(i) The submission conforms to the requirements of appendix V to this part; and

(ii) The State delivers five copies of the plan to the appropriate Regional Office, with a letter giving notice of such action.

(e)(1) The NO_X budget for a State listed in paragraph (c) of this section is defined as the total amount of NO_X emissions from all sources in that State, as indicated in paragraph (e)(2) of this section with respect to that State, which the State must demonstrate that it will not exceed in the 2007 ozone season pursuant to paragraph (g)(1) of this section.

(2) The State-by-State amounts of the NO_X budget, expressed in tons, are as follows:

State	Budget
Alabama	158,677
Connecticut	40,573
Delaware	18,523
District of Columbia	6,792
Georgia	177,381
Illinois	210,210
Indiana	202,584
Kentucky	155,698
Maryland	71,388
Massachusetts	78,168
Michigan	212,199
Missouri	114,532
New Jersey	97,034
New York	179,769
North Carolina	151,847
Ohio	239,898
Pennsylvania	252,447
Rhode Island	8,313
South Carolina	109,425
Tennessee	182,476
Virginia	155,718
West Virginia	92,920
Wisconsin	106,540
Total	3,023,113

(3)(i) Notwithstanding the State's obligation to comply with the budgets set forth in paragraph (e)(2) of this section, a SIP revision may allow sources required by the revision to implement NO_X emission control measures by May 1, 2003 to demonstrate compliance in the 2003 and 2004 ozone seasons using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(3)(iii) of this section.

(ii) A source may not use credit from the compliance supplement pool to demonstrate compliance after the 2004 ozone season.

(iii) The State-by-State amounts of the compliance supplement pool are as follows:

State	Compliance supplement pool (tons of NO_X)
Alabama	10,361
Connecticut	559
Delaware	417
District of Columbia	0
Georgia	10,919
Illinois	17,455
Indiana	19,738
Kentucky	13,018
Maryland	3,662
Massachusetts	285
Michigan	15,359
Missouri	10,469
New Jersey	1,722
New York	1,831
North Carolina	10,624
Ohio	22,947
Pennsylvania	13,716
Rhode Island	0
South Carolina	5,062
Tennessee	12,093
Virginia	6,108
West Virginia	16,937
Wisconsin	6,717
Total	200,000

(iv) The SIP revision may provide for the distribution of the compliance supplement pool to sources that are required to implement control measures using one or both of the following two mechanisms:

(A) The State may issue some or all of the compliance supplement pool to sources that implement emissions reductions during the ozone season beyond all applicable requirements in years prior to the year 2003 according to the following provisions:

(1) The State shall complete the issuance process by no later than May 1, 2003.

(2) The emissions reduction may not be required by the State's SIP or be otherwise required by the CAA.

(3) The emissions reduction must be verified by the source as actually having occurred during an ozone season between September 30, 1999 and May 1, 2003.

(4) The emissions reduction must be quantified according to procedures set forth in the SIP revision and approved by EPA. Emissions reductions implemented by sources serving electric generators with a nameplate capacity greater than 25 MWe, or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, must be quantified according to the requirements in paragraph (i)(4) of this section.

(5) If the SIP revision contains approved provisions for an emissions trading program, sources that receive credit according to the requirements of this paragraph may trade the credit to other sources or persons according to the provisions in the trading program.

(B) The State may issue some or all of the compliance supplement pool to sources that demonstrate a need for an extension of the May 1, 2003 compliance deadline according to the following provisions:

(1) The State shall initiate the issuance process by the later date of September 30, 2002 or after the State issues credit according to the procedures in paragraph (e)(3)(iv)(A) of this section.

(2) The State shall complete the issuance process by no later than May 1, 2003.

(3) The State shall issue credit to a source only if the source demonstrates the following:

(i) For a source used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible to import electricity from other electricity generation systems during the installation of control technologies necessary to comply with the SIP revision.

(ii) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(3)(iv)(B)(3)(i) of this section.

(iii) For a source subject to an approved SIP revision that allows for early reduction credits in accordance with paragraph (e)(3)(iv)(A) of this section, it was not possible for the source to comply with applicable control measures by generating early reduction credits or acquiring early reduction credits from other sources.

(iv) For a source subject to an approved emissions trading program, it was not possible to comply with applicable control measures by acquiring sufficient credit from other sources or persons subject to the emissions trading program.

(4) The State shall ensure the public an opportunity, through a public hearing process, to comment on the appropriateness of allocating compliance supplement pool credits to a source under paragraph (e)(3)(iv)(B) of this section.

(4) If, no later than November 23, 1998, any member of the public requests revisions to the source-specific data used to establish the State budgets set forth in paragraph (e)(2) of this section or the 2007 baseline sub-inventory information set forth in paragraph (g)(2)(ii) of this section, then EPA will act on that request no later than January 22, 1999, provided:

(i) The request is submitted in electronic format;

(ii) Information is provided to corroborate and justify the need for the requested modification;

(iii) The request includes the following data information regarding any electricity-generating source at issue:

(A) Federal Information Placement System (FIPS) State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Plant ID numbers (ORIS code preferred, State agency tracking number also or otherwise);

(E) Unit ID numbers (a unit is a boiler or other combustion device);

(F) Unit type;

(G) Primary fuel on a heat input basis;

(H) Maximum rated heat input capacity of unit;

(I) Nameplate capacity of the largest generator the unit serves;

(J) Ozone season heat inputs for the years 1995 and 1996;

(K) 1996 (or most recent) average NO_X rate for the ozone season;

(L) Latitude and longitude coordinates;

(M) Stack parameter information ;

(N) Operating parameter information;

(o) Identification of specific change to the inventory; and

(p) Reason for the change;

(iv) The request includes the following data information regarding any non-electricity generating point source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Facility primary standard industrial classification code (SIC);

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(E) Plant ID numbers (NEDS, AIRS/AFS, and State agency tracking number also or otherwise);

(F) Unit ID numbers (a unit is a boiler or other combustion device);

(G) Primary source classification code (SCC);

(H) Maximum rated heat input capacity of unit;

(I) 1995 ozone season or typical ozone season daily NO_X emissions;

(J) 1995 existing NO_X control efficiency;

(K) Latitude and longitude coordinates;

(L) Stack parameter information;

(M) Operating parameter information;

(N) Identification of specific change to the inventory; and

(O) Reason for the change;

(v) The request includes the following data information regarding any stationary area source or nonroad mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC);

(D) 1995 ozone season or typical ozone season daily NO_X emissions;

(E) 1995 existing NO_X control efficiency;

(F) Identification of specific change to the inventory; and

(G) Reason for the change;

(vi) The request includes the following data information regarding any highway mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC) or vehicle type;

(D) 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT);

(E) 1995 existing NO_X control programs;

(F) identification of specific change to the inventory; and

(G) reason for the change.

(f) Each SIP revision must set forth control measures to meet the NO_X budget in accordance with paragraph (b)(1)(i) of this section, which include the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2) Should a State elect to impose control measures on fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr as a means of meeting its NO_X budget, then those measures must: (i)(A) Impose a NO_X mass emissions cap on each source;

(B) Impose a NO_X emissions rate limit on each source and assume maximum operating capacity for every such source for purposes of estimating mass NO_X emissions; or

(C) Impose any other regulatory requirement which the State has demonstrated to EPA provides equivalent or greater assurance than options in paragraphs (f)(2)(i)(A) or (f)(2)(i)(B) of this section that the State will comply with its NO_X budget in the 2007 ozone season; and

(ii) Impose enforceable mechanisms to assure that collectively all such sources, including new or modified units, will not exceed in the 2007 ozone season the total NO_X emissions projected for such sources by the State pursuant to paragraph (g) of this section.

(3) For purposes of paragraph (f)(2) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(g)(1) Each SIP revision must demonstrate that the control measures contained in it are adequate to provide for the timely compliance with the State's NO_X budget during the 2007 ozone season.

(2) The demonstration must include the following:

(i) Each revision must contain a detailed baseline inventory of NO_X mass emissions from the following sources in the year 2007, absent the control measures specified in the SIP submission: electric generating units (EGU), non-electric generating units (non-EGU), area, nonroad and highway sources. The State must use the same baseline emissions inventory that EPA used in calculating the State's NO_X budget, as set forth for the State in paragraph (g)(2)(ii) of this section, except that EPA may direct the State to use different baseline inventory information if the State fails to certify that it has implemented all of the control measures assumed in developing the baseline inventory.

(ii) The base year 2007 NO_X emissions sub-inventories for each State, expressed in tons per ozone season, are as follows:

State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Alabama	76,900	49,781	25,225	16,594	50,111	218,610
Connecticut	5,600	5,273	4,588	9,584	18,762	43,807
Delaware	5,800	1,781	963	4,261	8,131	20,936
District of Columbia	[1] 0	310	741	3,470	2,082	6,603
Georgia	86,500	33,939	11,902	21,588	86,611	240,540
Illinois	119,300	55,721	7,822	47,035	81,297	311,174
Indiana	136,800	71,270	25,544	22,445	60,694	316,753
Kentucky	107,800	18,956	38,773	19,627	45,841	230,997
Maryland	32,600	10,982	4,105	17,249	27,634	92,570
Massachusetts	16,500	9,943	10,090	18,911	24,371]	79,815
Michigan	86,600	79,034	28,128	23,495	83,784	301,042
Missouri	82,100	13,433	6,603	17,723	55,230	175,089
New Jersey	18,400	22,228	11,098	21,163	34,106	106,995
New York	39,200	25,791	15,587	29,260	80,521	190,358
North Carolina	84,800	34,027	10,651	17,799	66,019	213,296
Ohio	163,100	53,241	19,425	37,781	99,079	372,626
Pennsylvania	123,100	73,748	17,103	25,554	92,280	331,785

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State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Rhode Island	1,100	327	420	2,073	4,375	8,295
South Carolina	36,300	34,740	8,359	11,903	47,404	138,706
Tennessee	70,900	60,004	11,990	44,567	64,965	252,426
Virginia	40,900	39,765	18,622	21,551	70,212	191,050
West Virginia	115,500	40,192	4,790	10,220	20,185	190,887
Wisconsin	52,000	22,796	8,160	12,965	49,470	145,391
Total	1,501,800	757,281	290,689	456,818	1,173,163	4,179,751

[1] The base case for the District of Columbia is actually projected to be 30 tons per season. The base case values in this table are rounded to the nearest 100 tons.

(iii) Each revision must contain a summary of NO_X mass emissions in 2007 projected to result from implementation of each of the control measures specified in the SIP submission and from all NO_X sources together following implementation of all such control measures, compared to the baseline 2007 NO_X emissions inventory for the State described in paragraph (g)(2)(i) of this section. The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2007 NO_X emissions that will be achieved from the implementation of the new control measures compared to the baseline emissions inventory.

(iv) Each revision must identify the sources of the data used in the projection of emissions.

(h) Each revision must comply with § 51.116 of this part (regarding data availability).

(i) Each revision must provide for monitoring the status of compliance with any control measures adopted to meet the NO_X budget. Specifically, the revision must meet the following requirements:

(1) The revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The revision must comply with § 51.212 of this part (regarding testing, inspection, enforcement, and complaints);

(3) If the revision contains any transportation control measures, then the revision must comply with § 51.213 of this part (regarding transportation control measures);

(4) If the revision contains measures to control fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, then the revision must require such sources to comply with the monitoring provisions of part 75, subpart H.

(5) For purposes of paragraph (i)(4) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year, provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(j) Each revision must show that the State has legal authority to carry out the revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's NO_X budget specified in paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards, and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources;

(4) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; also authority for the State to make such data available to the public as reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation which the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A revision may assign legal authority to local agencies in accordance with § 51.232 of this part.

(2) Each revision must comply with § 51.240 of this part (regarding general plan requirements).

(m) Each revision must comply with § 51.280 of this part (regarding resources).

(n) For purposes of the SIP revisions required by this section, EPA may make a finding as applicable under section 179(a)(1)–(4) of the CAA, 42 U.S.C. 7509(a)(1)–(4), starting the sanctions process set forth in section 179(a) of the CAA. Any such finding will be deemed a finding under § 52.31(c) of this part and sanctions will be imposed in accordance with the order of sanctions and the terms for such sanctions established in § 52.31 of this part.

(o) Each revision must provide for State compliance with the reporting requirements set forth in § 51.122 of this part.

(p)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to 40 CFR part 96 (the model NO_X budget trading program for SIPs), incorporates such part by reference into its regulations, or adopts regulations that differ substantively from such part only as set forth in paragraph (p)(2) of this section, then that portion of the State's SIP revision is automatically approved as satisfying the same portion of the State's NO_X emission reduction obligations as the State projects such regulations will satisfy, provided that:

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(i) The State has the legal authority to take such action and to implement its responsibilities under such regulations, and

(ii) The SIP revision accurately reflects the NO_X emissions reductions to be expected from the State's implementation of such regulations.

(2) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 in only the following respects, then such portion of the State's SIP revision is approved as set forth in paragraph (p)(1) of this section:

(i) The State may expand the applicability provisions of the trading program to include units (as defined in 40 CFR 96.2) that are smaller than the size criteria thresholds set forth in 40 CFR 96.4(a);

(ii) The State may decline to adopt the exemption provisions set forth in 40 CFR 96.4(b);

(iii) The State may decline to adopt the opt-in provisions set forth in subpart I of 40 CFR part 96;

(iv) The State may decline to adopt the allocation provisions set forth in subpart E of 40 CFR part 96 and may instead adopt any methodology for allocating NO_X allowances to individual sources, provided that:

(A) The State's methodology does not allow the State to allocate NO_X allowances in excess of the total amount of NO_X emissions which the State has assigned to its trading program; and

(B) The State's methodology conforms with the timing requirements for submission of allocations to the Administrator set forth in 40 CFR 96.41; and

(v) The State may decline to adopt the early reduction credit provisions set forth in 40 CFR 96.55(c) and may instead adopt any methodology for issuing credit from the State's compliance supplement pool that complies with paragraph (e)(3) of this section.

(3) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 other than as set forth in paragraph (p)(2) of this section, then such portion of the State's SIP revision is not automatically approved as set forth in paragraph (p)(1) of this section but will be reviewed by the Administrator for approvability in accordance with the other provisions of this section.

§ 51.122 Emissions reporting requirements for SIP revisions relating to budgets for NO_X emissions

(a) For its transport SIP revision under § 51.121 of this part, each State must submit to EPA NO_X emissions data as described in this section.

(b) Each revision must provide for periodic reporting by the State of NO_X emissions data to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) *Annual reporting.* Each revision must provide for annual reporting of NO_X emissions data as follows:

(i) The State must report to EPA emissions data from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.121(g) of this part. This would include all sources for which the State has adopted measures that differ from the measures incorporated into the baseline inventory for the year 2007 that the State developed in accordance with § 51.121(g) of this part.

(ii) If sources report NO_X emissions data to EPA annually pursuant to a trading program approved under § 51.121(p) of this part or pursuant to the monitoring and reporting requirements of subpart H of 40 CFR part 75, then the State need not provide annual reporting to EPA for such sources.

(2) *Triennial reporting.* Each plan must provide for triennial (i.e., every third year) reporting of NO_X emissions data from all sources within the State.

(3) *Year 2007 reporting.* Each plan must provide for reporting of year 2007 NO_X emissions data from all sources within the State.

(4) The data availability requirements in § 51.116 of this part must be followed for all data submitted to meet the requirements of paragraphs (b)(1),(2) and (3) of this section.

(c) The data reported in paragraph (b) of this section for stationary point sources must meet the following minimum criteria:

(1) For annual data reporting purposes the data must include the following minimum elements:

(i) Inventory year.

(ii) State Federal Information Placement System code.

(iii) County Federal Information Placement System code.

(iv) Federal ID code (plant).

(v) Federal ID code (point).

(vi) Federal ID code (process).

(vii) Federal ID code (stack).

(vii) Site name.

(viii) Physical address.

(ix) SCC.

(x) Pollutant code.

(xi) Ozone season emissions.

(xii) Area designation.

(2) In addition, the annual data must include the following minimum elements as applicable to the emissions estimation methodology.

(i) Fuel heat content (annual).

(ii) Fuel heat content (seasonal).

(iii) Source of fuel heat content data.

(iv) Activity throughput (annual).

(v) Activity throughput (seasonal).

(vi) Source of activity/throughput data.

(vii) Spring throughput (%).

(viii) Summer throughput (%).

(ix) Fall throughput (%).

(x) Work weekday emissions.

(xi) Emission factor.

(xii) Source of emission factor.

(xiii) Hour/day in operation.

(xiv) Operations Start time (hour).

(xv) Day/week in operation.

(xvi) Week/year in operation.

(3) The triennial and 2007 inventories must include the following data elements:

(i) The data required in paragraphs (c)(1) and (c)(2) of this section.

(ii) X coordinate (latitude).

(iii) Y coordinate (longitude).

(iv) Stack height.

(v) Stack diameter.

(vi) Exit gas temperature.

(vii) Exit gas velocity.

(viii) Exit gas flow rate.

(ix) SIC.

(x) Boiler/process throughput design capacity.

(xi) Maximum design rate.

(xii) Maximum capacity.

(xiii) Primary control efficiency.

(xiv) Secondary control efficiency.

(xv) Control device type.

(d) The data reported in paragraph (b) of this section for area sources must include the following minimum elements:

(1) For annual inventories it must include:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity/throughput level (annual).

(viii) Activity throughput level (seasonal).

(ix) Source of activity/throughput data.

(x) Spring throughput (%).

(xi) Summer throughput (%).

(xii) Fall throughput (%).

(xiii) Control efficiency (%).

(xiv) Pollutant code.

(xv) Ozone season emissions.

(xvi) Source of emissions data.

(xvii) Hour/day in operation.

(xviii) Day/week in operation.

(xix) Week/year in operations.

(2) The triennial and 2007 inventories must contain, at a minimum, all the data required in paragraph (d)(1) of this section.

(e) The data reported in paragraph (b) of this section for mobile sources must meet the following minimum criteria:

(1) For the annual, triennial, and 2007 inventory purposes, the following data must be reported:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity (this must be reported for both highway and nonroad activity. Submit nonroad activity in the form of hours of activity at standard load (either full load or average load) for each engine type, application, and horsepower range. Submit highway activity in the form of vehicle miles traveled (VMT) by vehicle class on each roadway type. Report both highway and nonroad activity for a typical ozone season weekday day, if the State uses EPA's default weekday/weekend activity ratio. If the State uses a different weekday/weekend activity ratio, submit separate activity level information for weekday days and weekend days).

(viii) Source of activity data.

(ix) Pollutant code.

(x) Summer work weekday emissions.

(xi) Ozone season emissions.

(xii) Source of emissions data.

(2) [Reserved]

(f) *Approval of ozone season calculation by EPA.* Each State must submit for EPA approval an example of the calculation procedure used to calculate ozone season emissions along with sufficient information for EPA to verify the calculated value of ozone season emissions.

(g) *Reporting schedules.* (1) Annual reports are to begin with data for emissions occurring in the year 2003.

(2) Triennial reports are to begin with data for emissions occurring in the year 2002.

(3) Year 2007 data are to be submitted for emissions occurring in the year 2007.

(4) States must submit data for a required year no later than 12 months after the end of the calendar year for which the data are collected.

(h) *Data reporting procedures.* When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(1) States are required to report emissions data in an electronic format to one of the locations listed in this paragraph (h). Several options are available for data reporting.

(2) An agency may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) system using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.)

(3) An agency may convert its emissions data into the Emission Inventory Improvement Program/Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network (VAN), or can be placed on a file transfer protocol (FTP) site.

(4) An agency may submit its emissions data in a proprietary format based on the EIIP data model.

(5) For options in paragraphs (h)(3) and (4) of this section, the terms submitting and reporting data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying this group that the data are available in the specified format and at a specific electronic location (e.g., FTP site).

(6) For annual reporting (not for triennial reports), a State may have sources submit the data directly to EPA to the extent the sources are subject to a trading program that qualifies for approval under § 51.121(q) of this part, and the State has agreed to accept data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

(i) *Definitions.* As used in this section, the following words and terms shall have the meanings set forth below:

(1) *Annual emissions.* Actual emissions for a plant, point, or process, either measured or calculated.

(2) *Ash content.* Inert residual portion of a fuel.

(3) *Area designation.* The designation of the area in which the reporting source is located with regard to the ozone NAAQS. This would include attainment or nonattainment designations. For nonattainment designations, the classification of the nonattainment area must be specified, i.e., transitional, marginal, moderate, serious, severe, or extreme.

(4) *Boiler design capacity.* A measure of the size of a boiler, based on the reported maximum continuous steam flow. Capacity is calculated in units of MMBtu/hr.

(5) *Control device type.* The name of the type of control device (e.g., wet scrubber, flaring, or process change).

(6) *Control efficiency.* The emissions reduction efficiency of a primary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(7) *Day/week in operations.* Days per week that the emitting process operates.

(8) *Emission factor.* Ratio relating emissions of a specific pollutant to an activity or material throughput level.

(9) *Exit gas flow rate.* Numeric value of stack gas flow rate.

(10) *Exit gas temperature.* Numeric value of an exit gas stream temperature.

(11) *Exit gas velocity.* Numeric value of an exit gas stream velocity.

(12) *Fall throughput (%).* Portion of throughput for the 3 fall months (September, October, November). This represents the expression of annual activity information on the basis of four seasons, typically spring, summer, fall, and winter. It can be represented either as a percentage of the annual activity (e.g., production in summer is 40 percent of the year's production), or in terms of the units of the activity (e.g., out of 600 units produced, spring = 150 units, summer = 250 units, fall = 150 units, and winter = 50 units).

(13) *Federal ID code (plant).* Unique codes for a plant or facility, containing one or more pollutant-emitting sources.

(14) *Federal ID code (point).* Unique codes for the point of generation of emissions, typically a physical piece of equipment.

(15) Federal ID code (stack number). Unique codes for the point where emissions from one or more processes are released into the atmosphere.

(16) *Federal Information Placement System (FIPS).* The system of unique numeric codes developed by the government to identify States, counties, towns, and townships for the entire United States, Puerto Rico, and Guam.

(17) *Heat content.* The thermal heat energy content of a solid, liquid, or gaseous fuel. Fuel heat content is typically expressed in units of Btu/lb of fuel, Btu/gal of fuel, joules/kg of fuel, etc.

(18) *Hr/day in operations.* Hours per day that the emitting process operates.

(19) *Maximum design rate.* Maximum fuel use rate based on the equipment's or process' physical size or operational capabilities.

(20) *Maximum nameplate capacity.* A measure of the size of a generator which is put on the unit's nameplate by the manufacturer. The data element is reported in megawatts (MW) or kilowatts (KW).

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(21) *Mobile source.* A motor vehicle, nonroad engine or nonroad vehicle, where:

(i) *Motor vehicle* means any self-propelled vehicle designed for transporting persons or property on a street or highway;

(ii) *Nonroad engine* means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;

(iii) *Nonroad vehicle* means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

(22) *Ozone season.* The period May 1 through September 30 of a year.

(23) *Physical address.* Street address of facility.

(24) *Point source.* A non-mobile source which emits 100 tons of NO_X or more per year unless the State designates as a point source a non-mobile source emitting at a specified level lower than 100 tons of NO_X per year. A non-mobile source which emits less NO_X per year than the point source threshold is an area source.

(25) *Pollutant code.* A unique code for each reported pollutant that has been assigned in the EIIP Data Model. Character names are used for criteria pollutants, while Chemical Abstracts Service (CAS) numbers are used for all other pollutants. Some States may be using storage and retrieval of aerometric data (SAROAD) codes for pollutants, but these should be able to be mapped to the EIIP Data Model pollutant codes.

(26) *Process rate/throughput.* A measurable factor or parameter that is directly or indirectly related to the emissions of an air pollution source. Depending on the type of source category, activity information may refer to the amount of fuel combusted, the amount of a raw material processed, the amount of a product that is manufactured, the amount of a material that is handled or processed, population, employment, number of units, or miles traveled. Activity information is typically the value that is multiplied against an emission factor to generate an emissions estimate.

(27) *SCC. Source category code.* A process-level code that describes the equipment or operation emitting pollutants.

(28) *Secondary control efficiency (%).* The emissions reductions efficiency of a secondary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(29) *SIC.* Standard Industrial Classification code. U.S. Department of Commerce's categorization of businesses by their products or services.

(30) *Site name.* The name of the facility.

(31) *Spring throughput (%).* Portion of throughput or activity for the 3 spring months (March, April, May). See the definition of Fall Throughput.

(32) *Stack diameter.* Stack physical diameter.

(33) *Stack height.* Stack physical height above the surrounding terrain.

(34) *Start date (inventory year).* The calendar year that the emissions estimates were calculated for and are applicable to.

(35) *Start time (hour).* Start time (if available) that was applicable and used for calculations of emissions estimates.

(36) *Summer throughput (%).* Portion of throughput or activity for the 3 summer months (June, July, August). See the definition of Fall Throughput.

(37) Summer work weekday emissions. Average day's emissions for a typical day.

(38) *VMT by Roadway Class.* This is an expression of vehicle activity that is used with emission factors. The emission factors are usually expressed in terms of grams per mile of travel. Since VMT does not directly correlate to emissions that occur while the vehicle is not moving, these non-moving emissions are incorporated into EPA's MOBILE model emission factors.

(39) *Week/ year in operation.* Weeks per year that the emitting process operates.

(40) *Work Weekday.* Any day of the week except Saturday or Sunday.

(41) *X coordinate (latitude).* East-west geographic coordinate of an object.

(42) *Y coordinate (longitude).* North-south geographic coordinate of an object.

PART 72—PERMITS REGULATION

1. The authority for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 72.2 is amended by revising the definition for ''excepted monitoring system,'' and adding new definitions in alphabetical order for ''low mass emissions unit'', ''maximum potential hourly heat input'', ''maximum rated hourly heat input,'' and ''ozone season'' to read as follows:

§ 72.2 Definitions.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.19 of this chapter or of appendix D or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Low mass emissions unit means an affected unit that is a gas-fired or oil-fired unit, burns only natural gas or fuel oil and qualifies under § 75.19 of this chapter.

* * * * *

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

* * * * *

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

* * * * *

Ozone season means the period of time beginning May 1 of a year and ending on September 30 of the same year, inclusive.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

3. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651k, 7651 and note.

4. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990). In addition, this part sets forth

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provisions for the monitoring, recordkeeping, and reporting of NO_X mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

* * * * *

5. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

* * * * *

(c) The provisions of this part apply to sources subject to a State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

6. Section 75.4 is amended by revising paragraph (a) introductory text to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (h) of this section):

* * * * *

7. Section 75.6 is amended by adding paragraph (f) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19.

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992), for § 75.19.

8. Section 75.11 is amended by removing the period at the end of paragraph (d)(2) and replacing it with ''; or'' and adding paragraph (d)(3), to read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

* * * * *

(d)* * *

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

* * * * *

9. Section 75.12 is amended by revising the section heading, by redesignating paragraph (d) as paragraph (e), and by adding new paragraph (d) to read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X and diluent gas monitors).

* * * * *

(d) Low mass emissions units. Notwithstanding the requirements of paragraphs (a) and (c) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

10. Section 75.13 is amended by adding paragraph (d) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(d) Determination of CO_2 mass emissions from low mass emissions units. The owner or operator of a unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

11. Section 75.17 is amended by adding introductory text before paragraph (a) to read as follows:

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_X emission rate.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the provisions for monitoring NO_X emission rate in §§ 75.71 and 75.72.

* * * * *

12. Section 75.19 is added to subpart B to read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2 mass emissions from a low mass emissions unit.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired unit, that burns only natural gas or fuel oil and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually; and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emission unit continues to emit no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually.

(ii) Any qualifying unit must start using the low mass emissions excepted methodology in the first hour in which the unit operates in a calendar year. Notwithstanding, the earliest date for which a unit that meets the eligibility requirements of this section may begin to use this methodology is January 1, 2000.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) If the designated representative submits a certification application to use the low mass emissions excepted methodology and the Administrator certifies the use of such methodology. The certification application must contain:

(A) Actual SO_2 and NO_X mass emissions data for each of the three calendar years prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually; and

(B) Calculated SO_2 and NO_X mass emissions, for each of the three calendar years prior to the calendar year in which the certification application is submitted, demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually. The calculated emissions for each year shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2, NO_X, and CO_2 emission rate from paragraph (c)(1)(i) of this section for SO_2, paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X and paragraph (c)(1)(iii) of this section for CO_2; or

(ii) When the three full years of actual, historical SO_2 and NO_X mass emissions data required under paragraph (a)(2)(i) of this section are not available, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of historical SO_2 and NO_X mass emissions data and projected SO_2 and NO_X mass emissions, totaling three years. Historical data must be used for any years in which historical data exists and projected data should be used for any remaining future years needed to provide capacity factor data for three consecutive calender years. For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for unit that commenced operation after January 1, 1997, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than 25 tons of SO_2 and less than 50 tons of NO_X annually. Projected emissions shall be calculated using either the default emission rates in tables 1,2 and 3 of this section, or for NO_X emission rate a fuel-and-unit-specific NO_X emission rate determined in accordance with the testing procedures in paragraph (c)(1)(iv) of this section, in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section.

(b) On-going qualification and disqualification. (1) Once a low mass emission unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit less than 25 tons of SO_2 annually and less than 50 tons of NO_X annually. The calculation methodology used for the annual demonstration shall be the same methodology, from paragraph (c) of this section, by which the unit initially qualified to use the low mass emissions excepted methodology.

(2) If any low mass emission unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative year-to-date emissions for the unit exceed 25 tons of SO_2 or 50 tons of NO_X in any calendar quarter of any calendar year, then;

(i) The low mass emission unit shall be disqualified from using the low mass emissions excepted methodology as of the end of the second calendar quarter following such quarter in which either the 25 ton limit for SO_2 or the 50 ton limit for NO_X was exceeded; and

(ii) The owner or operator of the low mass emission unit shall have two calendar quarters from the end of the quarter in which the unit exceeded the 25 ton limit for SO_2 or the 50 ton limit for NO_X to install, certify, and report SO_2, NO_X, and CO_2 emissions from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13.

(3) If a low mass emission unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology (e.g. natural gas or fuel oil) is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install, certify, and report SO_2, NO_X, and CO_2 from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel. The owner or operator must notify the Administrator in the case where a unit switches fuels without previously having installed and certified a SO_2, NO_X and CO_2 monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.

(4) If a unit commencing operation after January 1, 1997 initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use a low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a unit subject to a NO_X mass reduction program;

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(ii) Use these records to determine the cumulative heat input and SO_2, NO_X, and CO_2 mass emissions in order to continue to qualify as a low mass emission unit; and

(iii) Determine the cumulative SO_2 and NO_X mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in tables 1, 2 and 3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. The Administrator will not count SO_2 mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under § 75.4 against SO_2 allowances to be held in the unit account.

(5) A low mass emission unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again only if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) Low mass emissions excepted methodology, calculations, and values.

(1) *Determination of SO_2, NO_X, and CO_2 emission rates.*

(i) Use Table 1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section.

(ii) Use either the appropriate NO_X emission factor from Table 2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section.

(iii) Use Table 3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section.

(iv) In lieu of using the default NO_X emission rate from Table 2 of this section, the owner or operator may, for each fuel combusted by a low mass emission unit, determine a fuel-and-unit-specific NO_X emission rate forthe purpose of calculating NO_X mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F) and (G) of this paragraph, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(1) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(2) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(1) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(2) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table 4 of this section.

(3) If there are only two low mass emission units in the group of identical units, the results of the representative testing under paragraph (c)(1)(iv)(B)(1) of this section may be used to establish the fuel-and-unit-specific NO_X emission rate(s) for the units. However, if there are more than two low mass emission units in the group, the testing must confirm that the units are identical by meeting the following criteria. The results of the representative testing may only be used to establish the fuel-and-unit-specific NO_X emission rate(s) for such units if the following criteria are met:

(i) at each of the four load levels tested, the NO_X emission rate for each tested low mass emission unit does not differ by more than ±10 % from the average of the NO_X emission rates for all units tested, or;

(ii) if the average NO_X emission rate of all low mass emission units tested at all four load levels is less than 0.20 lb/mmBtu, an alternative criteria of ±0.020 lb/mmBtu may be use in lieu of the 10 % criteria. Units must all be within +0.020 lb/mmBtu of the average from the test to be considered identical units under this section.

(4) If the acceptance criteria in paragaph (c)(1)(iv)(B)(3) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(5) Fuel and unit specific NO_X emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the appendix E testing, determine the fuel- and-unit-specific NO_X emission rate as follows:

(1) For an individual low mass emission unit with no NO_X emissions controls of any kind, the highest NO_X emission rate obtained for a particular type of fuel in the appendix E test multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(2) For a group of low mass emission units sharing a common fuel supply with no NO_X controls of any kind on any of the units, the highest NO_X emission rate obtained for a particular type of fuel in all of the appendix E tests of all units in the group of units sharing a common fuel supply multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate for each unit in the group, for that type of fuel.

(3) For a group of identical low mass emission units which perform representative testing according to paragraph (c)(1)(iv)(B) of this section with no NO_X controls of any kind on any of the units, the fuel-and-unit-specific NO_X emission rate for all units, for a particular type of fuel, multiplied by 1.15 shall be the highest NO_X

emission rate from any unit tested in the group, for that type of fuel.

(4) For an individual low mass emission unit which has NO_X emission controls of any kind, the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(i) The highest emission rate from the appendix E test for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(5) For a group of low mass emission units sharing a common fuel supply, one or more of which has NO_X controls of any kind, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units sharing a common fuel supply shall, for a particular type of fuel combusted by the group of units sharing a common fuel supply, shall be the higher of:

(i) The highest NO_X emission rate from all appendix E tests of all low mass emission units in the group for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(6) For a group of identical low mass emission units, which perform representative testing according to paragraph (c)(1)(iv)(B) of this section and have identical NO_X controls, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(i) The highest NO_X emission rate from all appendix E tests of all tested low mass emission units in the group of identical units for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(D) For each low mass emission unit, each unit in a group of units sharing a common fuel supply, or identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_X emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_X emission rate every five years, unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate. If such changes occur, the fuel-and-unit-specific NO_X emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. If a low mass emission unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_X emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_X emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rates.

(E) Each low mass emission unit, each low mass emission unit in a group of units combusting a common fuel, or each low mass emission unit in a group of identical units for which a fuel-and-unit-specific NO_X emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_X emission rate(s). However, fuel-and-unit-specific NO_X emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emission units for which at least 3 years of NO_X emission rate continuous emissions monitoring system data and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. Separate the actual NO_X emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_X emission rate. Determine the 95th percentile NO_X emission rate for each data set as defined in § 72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_X emission rate, except that for a unit with NO_X emission controls of any kind, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_X emission rate.

(H) For low mass emission units with NO_X emission controls, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_X emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_X controls are operating properly and to allow the determination of the correct NO_X emission rate as required under paragraph (c)(1)(iv) of this section.

(1) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_X emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_X controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to- fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_X emission rate may not be used for that hour.

(2) For low mass emission units with other types of NO_X controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_X controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_X emission rates may not be used in that hour.

(2) Records of operating time, fuel usage, unit output and NO_X emission control operating status. The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection:

(i) For each low mass emission unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type(s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emission unit using the long term fuel flow methodology under paragraph (c)(3)(ii)

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of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit output (in megawatts or thousands of pounds of steam), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emission unit with NO_X emission controls of any kind, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_X controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emission unit shall be determined using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, the hourly heat input (mmBtu) to a low mass emission unit shall be deemed to equal the maximum rated hourly heat input, as defined in § 72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr}, in mmBtu, shall be determined using Equation LM–1:

$$HI_{qtr} = T_{qtr} \times HI_{hr} \qquad \text{(Eq. LM–1)}$$

Where:

T_{qtr} = Actual number of operating hours in the quarter (hr).

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(ii) Long term fuel flow heat input method. The owner or operator may, for the purpose of demonstrating that a low mass emission unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emission unit.

(A) This option may be used for a group of low mass emission units only if:

(*1*) The low mass emission units combust fuel from a common source of supply; and

(*2*) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(*3*) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;

(*1*) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(*2*) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6); or;

(*3*) A fuel flow meter certified and maintained according to appendix D to this part.

(C) For each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default gross calorific value listed in Table 5 of this section.

(D) For each type of fuel oil combusted during the quarter, the specific gravity of the oil shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default specific gravity value in Table 5 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emission unit or group of low mass emission units sharing a common fuel supply shall be determined using Equation LM–2 for oil and LM–3 for natural gas.

$$HI_{fuel\text{--}qtr} = M_{qtr} \frac{GCV_{max}}{10^6}$$

Eq LM–2 (for fuel oil or diesel fuel)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the entire quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb)

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{--}qtr} = Q_g \frac{GCV_{max}}{10^6}$$

Eq LM–3 (for natural gas)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly heat input from natural gas (mmBtu).

Q_g = Value of natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf).

GCV_g = Gross calorific value of the natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf)

10^6 = Conversion of Btu to mmBtu.

(F) The quarterly heat input (mmBtu) for all fuels for the quarter, $HI_{qtr\text{-}total}$, shall be the sum of the $HI_{fuel\text{-}qtr}$ values determined using Equations LM–2 and LM–3.

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$$HI_{qtr\text{--}total} = \sum_{all\text{--}fuels} HI_{fuel\text{--}qtr}$$

(Eq. LM–4)

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input ($HI_{qtr\text{-}total}$) values for all calendar quarters in the year to date.

(H) For each low mass emission unit, each low mass emission unit of an identical group of units, or each low mass emission unit in a group of units sharing a common fuel supply, the owner or operator shall determine the quarterly unit output in megawatts or pounds of steam. The quarterly unit output shall be the sum of the hourly unit output values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6.

$$MW_{qtr} = \sum_{all\text{--}hours} MW$$

Eq LM–5 (for MW output)

$$ST_{qtr} = \sum_{all\text{--}hours} ST$$

Eq LM–6 (for steam output)

Where:

MW_{qtr} = the power produced during all hours of operation during the quarter by the unit (MW)

$ST_{fuel\text{-}qtr}$ = the total quarterly steam output produced during all hours of operation during the quarter by the unit (klb)

MW = the power produced during each hour in which the unit operated during the quarter (MW).

ST = the steam output produced during each hour in which the unit operated during the quarter (klb)

(I) For a low mass emission unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr\text{-}total}$ to each hour of unit operation using either Equation LM–7 or LM–8:

$$HI_{hr} = HI_{qtr\text{--}total} \frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM–7 for MW output)

$$HI_{hr} = HI_{qtr\text{--}total} \frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM–8 for steam output)

Where:

HI_{hr} = hourly heat input to the unit (mmBtu)

MW_{hr} = hourly output from the unit (MW)

ST_{hr} = hourly steam output from the unit (klb)

(J) For each low mass emission unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr\text{-}total}$ to each hour of operation using either Equation LM–7a or LM–8a:

$$HI_{hr} = HI_{qtr\text{--}total} \frac{MW_{hr}}{\sum_{all\text{--}units} MW_{qtr}}$$

(Eq LM–7a for MW output)

$$HI_{hr} = HI_{qtr\text{--}total} \frac{ST_{hr}}{\sum_{all\text{--}units} ST_{qtr}}$$

(Eq LM–8a for steam output)

Where:

HI_{hr} = hourly heat input to the individual unit (mmBtu)

MW_{hr} = hourly output from the individual unit (MW)

ST_{hr} = hourly steam output from the individual unit (klb)

$\sum_{all\text{--}units} MW_{qtr}$ = Sum of the quarterly outputs (from Eq. LM-5) for all units in the group (MW)

$\sum_{all\text{--}units} ST_{qtr}$ = Sum of the quarterly steam outputs (from Eq. LM-6) for all units in the group (klb)

(4) *Calculation of SO_2, NO_X and CO_2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emission unit meets the requirements of this section, calculate SO_2, NO_X and CO_2 mass emissions in accordance with the following.

(i) *SO_2* mass emissions. (A) The hourly SO_2 mass emissions (lbs) for a low mass emission unit shall be determined using Equation LM–9 and the appropriate fuel-based SO_2 emission factor from Table 1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$W_{SO2} = EF_{SO2} \times HI_{hr}$ (Eq. LM–9)

where:

W_{SO2}=Hourly SO_2 mass emissions (lbs).

EF_{SO2}=SO_2 emission factor from Table 1 of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO_X mass emissions.* (A) The hourly NO_X mass emissions for the low mass emission unit (lbs) shall be determined using Equation LM–10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_X emission controls of any kind and for which a fuel-and-unit-specific NO_X emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_X emission controls are operating properly, use the NO_X emission rate from Table 2 of this section for the fuel combusted during the hour with the highest NO_X emission rate.

$W_{NOx} = EF_{NOx} \times HI_{hr}$ (Eq. LM–10)

Where:

WNO_X=Hourly NO_X mass emissions (lbs).

$EFNO_X$=Either the NO_X emission factor from Table 1b of paragraph (c)(1)(ii) of this section of this section or the fuel-and-unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph(c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_X mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly NO_X mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_X mass emissions (tons) for the low mass emission unit shall be the sum of the

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quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date.

(iii) *CO_2 Mass Emissions.* (A) The hourly CO_2 mass emissions (tons) for the affected low mass emission unit shall be determined using Equation LM–11 and the appropriate fuel-based CO_2 emission factor from Table 3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$W_{CO_2} = EF_{CO_2} \times HI_{hr} \qquad \text{(Eq. LM–11)}$$

Where:

W_{CO_2} = Hourly CO mass emissions (tons).

EF_{CO_2} = Fuel-based CO_2 emission factor from Table 3 of this section (ton/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly CO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly CO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A)of this section.

(C) The year-to-date cumulative CO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all of the quarterly CO_2 mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.

(d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.

(e) The quality control and quality assurance requirements in § 75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

(1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for long term fuel flow determinations.

(2) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997, Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6), to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

(3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.

(4) For each low mass emission unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_X emission rate tests conducted according to appendix E to this part. If CEMS data are used to determine the fuel-and-unit-specific NO_X emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_X emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_X emission rates are re-determined.

(5) For each low mass emission unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which have NO_X emission controls of any kind, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_X controls.

TABLE 1 OF § 75.19: SO_2 EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES

Fuel type	SO_2 emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

TABLE 2 OF § 75.19: NO_X EMISSION RATES (LB/MMBTU) FOR VARIOUS BOILER/FUEL TYPES

Boiler type	Fuel type	NO_X emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

TABLE 3 OF § 75.19: CO_2 EMISSION FACTORS (TON/MMBTU) FOR GAS AND OIL

Fuel type	CO_2 emission factors
Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2

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TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS—Continued

Number of identical units in the group	Number of appendix E tests required
7	3
> 7	n tests; wheren n = number of units divided by 3 and rounded to nearest integer.

TABLE 5 OF § 75.19: DEFAULT GROSS CALORIFIC VALUES (GCVS) FOR VARIOUS FUELS

Fuel	GCV for use in equation LM–2 or LM–3
Pipeline Natural Gas	1051 Btu/scf.
Natural Gas	1118 Btu/scf.
Residual Oil	19,708 Btu/gallon.
Diesel Fuel	20,500 Btu/gallon.

TABLE 6 OF § 75.19: DEFAULT SPECIFIC GRAVITY VALUES FOR FUEL OIL

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

13. Section 75.20 is amended by adding new paragraph (h) to read as follows:

§ 75.20 Certification and recertification procedures.

* * * * *

(h) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph.

(1) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62. The designated representative for an owner or operator who wishes to use fuel-and unit-specific NO_X emission rate testing for units with NO_X controls under § 75.19(c)(1)(iv) must submit in the monitoring plan the parameters monitored which will be used to determine operation of the NO_X emission controls. For units using water or steam injection to control NO_X, the water-to-fuel or steam-to-fuel range of values must be documented.

(2) Certification application. [reserved]

(3) Approval of certification applications. The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted methodology.'' The excepted methodology shall be deemed provisionally certified for use under the Acid Rain Program, as of the following dates:

(i) For a unit that commenced operation on or before January 1, 1997, from January 1 of the year following submission of the certification application until the completion of the period for the Administrator's review; or

(ii) For a unit that commenced operation after January 1, 1997, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 until the completion of the period for the Administrator's review, except that the methodology may be used retrospectively until the date and hour that the unit commenced operation for purposes of demonstrating that the unit qualified to use the methodology under § 75.19(b)(4)(iii).

(4) *Disapproval of certification applications* . If the Administrator determines that the certification application does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data recorded under the excepted methodology shall not be considered valid. The owner or operator shall follow the procedures for loss of certification:

(i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §§ 75.21(e) (introductory paragraph) and 75.21(e)(1): the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter to report NO_X emission rate; the maximum potential flow rate, as defined in section 2.1 of appendix A to this part to report volumetric flow; or the maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A to this part to report CO_2 concentration data. For a unit subject to a State or federal NO_X mass reduction program where the owner or operator intends to monitor NO_X mass emissions with a NO_X pollutant concentration monitor and a flow monitoring system, substitute for NO_X concentration using the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, and substitute for volumetric flow using the maximum potential flow rate, as defined in section 2.1 of appendix A to this part. The owner or operator shall substitute these values until such time, date, and hour as a continuous emission monitoring system or excepted monitoring system, where applicable, is installed and provisionally certified;

(ii) The designated representative shall submit a notification of certification test dates, as specified in § 75.61(a)(1)(ii), and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall install and provisionally certify continuous emission monitoring systems or excepted monitoring systems, where applicable, two calendar quarters from the end of the quarter in which the unit no longer qualifies as a low mass emissions unit.

14. Section 75.24 is amended by revising paragraph (d) to read as follows:

§ 75.24 Out-of-control periods.

* * * * *

(d) When the bias test indicates that an SO_2 monitor, a volumetric flow monitor, a NO_X continuous emission monitoring system or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test, or calculate and use the bias adjustment factor as specified in section 2.3.3 of appendix B to this part and in accordance with § 75.7.

* * * * *

16. Subpart H is added to part 75 to read as follows:

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Subpart H—NO_X Mass Emissions Provisions

Subpart H—NO_X Mass Emissions Provisions

§ 75.70 NO_X mass emissions provisions.

(a) *Applicability* . The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

(1) For purposes of this subpart, the term ''affected unit'' shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''nonaffected unit'' shall mean any unit that is not subject to such a program, the term ''permitting authority'' shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to NO_X concentration, flow rate, NO_X emission rate and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or federal NO_X mass emission reduction program. When applying these requirements, the term ''affected unit'' shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''permitting authority'' shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The requirements of this part for SO_2, CO_2 and opacity monitoring, recordkeeping and reporting do not apply to units that are subject to a State or federal NO_X mass emission reduction program only and are not affected units with an Acid Rain emission limitation.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non- affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_X to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part, except as provided in § 75.74.

(3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under § 75.71, except as provided in § 75.74.

(4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart;

(ii) The owner or operator is monitoring NO_X mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.61.

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of this part, except that the owner or operator shall meet any additional requirements set forth in an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart for any additional NO_X-diluent CEMS, flow monitors, diluent monitors or NO_X concentration monitoring system required under the NO_X mass emissions provisions of § 75.71 or the common stack provisions in § 75.72.

(e) Quality assurance and quality control requirements. For units that use continuous emission monitoring systems to account for NO_X mass emissions, the owner or operator shall meet the quality assurance and quality control requirements in § 75.21 that apply to NO_X-diluent continuous emission monitoring systems, flow monitoring systems, NO_X concentration monitoring systems, and diluent monitors under § 75.71. A NO_X concentration monitoring system for determining NO_X mass emissions in accordance with § 75.71 shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as are specified in this part for an SO_2 pollutant concentration monitor. Units using excepted methods under § 75.19 shall meet the applicable quality assurance requirements of that section, and units using excepted monitoring methods under appendix D and E to this part shall meet the applicable quality

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assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in § 75.34 and paragraph (g) of this section, the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

(1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the missing data procedures in subpart D of this part whenever the unit combusts fuel and:

(i) A valid quality assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured and recorded for a unit by a certified NO_X-diluent continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(ii) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for a unit from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part; or

(iii) A valid quality assured hour of heat input data (in mmBtu) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part or by an accepted monitoring system under appendix D to this part, where heat input is required either for calculating NO_X mass or allocating allowances under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart; or

(iv) A valid, quality-assured hour of NO_X concentration data (in ppm) has not been measured and recorded by a certified NO_X concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_X concentration monitoring system with a volumetric flow monitor, and without a diluent monitor, to calculate NO_X mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_X concentration monitoring system shall be the same as the procedures specified for a NO_X-diluent continuous emission monitoring system under §§ 75.31, 75.32 and 75.33, except that the phrase ''NO_X concentration monitoring system'' shall be substituted for the phrase ''NO_X continuous emission monitoring system'', the phrase ''NO_X concentration'' shall be substituted for ''NO_X emission rate'; and the phrase ''maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A of this part'' shall be substituted for the phrase ''maximum potential NO_X emission rate, as defined in § 72.2 of this chapter''.

(2) For an owner or operator using an excepted monitoring system under appendix D or E of this part, substitute for missing data in accordance with the missing data procedures in section 2.4 of appendix D to this part or in section 2.5 of appendix E to this part whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of fuel flow rate data has not been measured and recorded by a certified fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part; or

(ii) A fuel sample value for gross calorific value, or if necessary, density or specific gravity, from a sample taken an analyzed in accordance with appendix D of this part is not available; or

(iii) A valid, quality-assured hour of NO_X emission rate data has not been obtained according to the procedures and specifications of appendix E to this part.

(g) Reporting data prior to initial certification. If the owner or operator of an affected unit has not successfully completed all certification tests required by the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart by the applicable date required by that program, he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, consistent with the monitoring equipment to be certified:

(1) For units that the owner or operator intends to monitor for NO_X mass emissions using NO_X emission rate and heat input, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(2) For units that the owner or operator intends to monitor for NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of Appendix A of this part;

(3) For any unit, the reference methods under § 75.22 of this part.

(4) For any unit using the low mass emission excepted monitoring methodology under § 75.19, the procedures in paragraphs (g)(1) or (2) of this section.

(5) Any unit using the procedures in paragraph (g)(2) of this section that is required to report heat input for purposes of allocating allowances shall also report the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(h) *Petitions.* (1) The designated representative of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or federal NO_X mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72 shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (h)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The designated representative of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by the Administrator and by the permitting authority if required by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

§ 75.71 Specific provisions for monitoring NO_X emission rate and heat input for the purpose of calculating NO_X mass emissions.

(a) *Coal-fired units.* The owner or operator of a coal-fired affected unit shall either:

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(1) Meet the general operating requirements in § 75.10 for a NO_X-diluent continuous emission monitoring system (consisting of a NO_X pollutant concentration monitor, an O_2- or CO_2-diluent gas monitor, and a data acquisition and handling system) to measure NO_X emission rate and for a flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, except as provided in accordance with subpart E of this part; or

(2) Meet the general operating requirements in § 75.10 for a NO_X concentration monitoring system (consisting of a NO_X pollutant concentration monitor and a data acquisition and handling system) to measure NO_X concentration and for a flow monitoring system. In addition, if heat input is required to be reported under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating requirements for a flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, or, if applicable, use the procedures in appendix D to this part. These requirements must be met, except as provided in accordance with subpart E of this part.

(b) *Moisture correction.* If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu (i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor) or NO_X mass emissions in tons (i.e., if the NO_X concentration monitoring system or diluent monitor measures on a different moisture basis from the flow rate monitor), the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.11(b) except that the term ''SO_2'' shall be replaced by the term ''NO_X'.

(c) Gas-fired nonpeaking units or oil-fired nonpeaking units. The owner or operator of an affected unit that, based on information submitted by the designated representative in the monitoring plan, qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in § 75.10 for a NO_X-diluent continuous emission monitoring system, except as provided in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart, except as provided in § 75.72(a); or

(3) Meet the requirements of the low mass emission excepted methodology under paragraph (e)(2) of this section and under § 75.19, if applicable.

(d) *Gas-fired or oil-fired peaking units.* The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedures specified in appendix E to this part for estimating hourly NO_X emission rate. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart except for units using an excepted monitoring system under appendix E to this part and except as provided in § 75.72(a). In addition, if after certification of an excepted monitoring system under appendix E to this part, a unit's operations exceed a capacity factor of 20.0 percent in any calender year or exceed a capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c) of this section or, if applicable, paragraph (e) of this section, by no later than December 31 of the following calender year.

(e) Low mass emissions units. Notwithstanding the requirements of paragraphs (c) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) shall comply with one of the following:

(1) Meet the applicable requirements specified in paragraphs (c) or (d) of this section; or

(2) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly emission rate, hourly heat input, and hourly NO_X mass emissions.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

§ 75.72 Determination of NO_X mass emissions.

Except as provided in paragraphs (e) and (f) of this section, the owner or operator of an affected unit shall calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hr). The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Record the combined NO_X mass emissions for the units exhausting to the common stack, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in the common stack, and either:

(i) Install, certify, operate, and maintain a flow monitoring system at the common stack. The owner or operator also shall provide heat input values for each unit, either by monitoring each unit individually using a flow monitor and a diluent monitor or by apportioning heat input according to the procedures in § 75.16(e)(5); or

(ii) If any of the units using the common stack are eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to this part to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in the duct to the common stack from each unit and either:

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each unit; or

(ii) For any unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit.

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(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each affected unit; and

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each affected unit; or

(ii) For any affected unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable State or federal NO_X mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii) Install, certify, operate, and maintain a flow monitoring system in the common stack and a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each nonaffected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_X mass emissions from the affected units as the difference between NO_X mass emissions measured in the common stack and NO_X mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated. In addition, the owner or operator shall also either:

(A) Install, certify, operate, and maintain a flow monitoring system in the duct from each nonaffected unit or,

(B) For any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input using the procedures in appendix D for that unit. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart. For any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitoring system in the duct to the common stack; or

(iii) Install a flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_X mass emissions for the affected units for recordkeeping and compliance purposes; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_X mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_X mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated.

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed to avoid the installed NO_X-diluent continuous emissions monitoring system or NO_X concentration monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system on the bypass flue, duct, or stack gas stream and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by all required monitoring systems; or

(2) Monitor NO_X mass emissions on the bypass flue, duct, or stack gas stream using the reference methods in § 75.22(b) for NO_X concentration, flow, and diluent, or NO_X concentration and flow, and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems.

(d) Unit with multiple stacks. Notwithstanding § 75.17(c), when the flue gases from a affected unit discharge to the atmosphere through more than one stack, or when the flue gases from a unit subject to a NO_X mass emission reduction program utilize two or more ducts feeding into two or more stacks (which may include flue gases from other affected or nonaffected unit(s)), or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system and a flow monitoring system in each duct feeding into the stack or stacks and determine NO_X mass emissions from each affected unit using the stack or stacks as the sum of the NO_X mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in each stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions recorded for each stack, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record NO_X mass emissions from the units using that stack; or

(3) If the unit is eligible to use the procedures in appendix D to this part, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or stacks and use the procedures in appendix D to this part to determine heat input for the unit, provided that:

(i) There are no add-on NO_X controls at the unit;

(ii) The unit is not capable of emitting solely through an unmonitored stack (e.g., has no dampers); and

(iii) The owner or operator of the unit demonstrates to the satisfaction of the permitting authority and the Administrator that the NO_X emission rate in the monitored duct or stack is representative of the NO_X emission rate in each duct or stack.

(e) Units using a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass. The owner or operator may use a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass emissions in paragraphs (a) through (d) of this section (in place of a NO_X-diluent continuous emission monitoring system and a flow monitoring system). When using this approach, calculate NO_X mass according to sections 8.2 and 8.3 in appendix F of this part. In addition, if an applicable

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State or federal NO_X mass reduction program requires determination of a unit's heat input, the owner or operator must either:

(1) Install, certify, operate, and maintain a CO_2 or O_2 diluent monitor in the same location as each flow monitoring system. In addition, the owner or operator must provide heat input values for each unit utilizing a common stack by either:

(i) Apportion heat input from the common stack to each unit according to § 75.16(e)(5), where all units utilizing the common stack are affected units, or

(ii) Measure heat input from each affected unit, using a flow monitor and a CO_2 or O_2 diluent monitor in the duct from each affected unit; or

(2) For units that are eligible to use appendix D to this part, use the procedures in appendix D to this part to determine heat input for the unit. However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of appendix D of this part are not applicable to any unit that is using the provisions of this subpart to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program and that shares a common pipe or a common stack with a nonaffected unit.

(f) *Units using the low mass emitter excepted methodology under § 75.19.* For units that are using the low mass emitter excepted methodology under § 75.19, calculate ozone season NO_X mass emissions by summing all of the hourly NO_X mass emissions in the ozone season, as determined under paragraph § 75.19(c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(g) *Procedures for apportioning heat input to the unit level.* If the owner or operator of a unit using the common stack monitoring provisions in paragraphs (a) or (b) of this section does not monitor and record heat input at the unit level and the owner or operator is required to do so under an applicable State or federal NO_X mass emission reduction program, the owner or operator should apportion heat input from the common stack to each unit according to § 75.16(e)(5).

§ 75.73 Recordkeeping and reporting. [Reserved]

§ 75.74 Annual and ozone season monitoring and reporting requirements.

(a) Annual monitoring requirement. (1) The owner or operator of an affected unit subject both to an Acid Rain emission limitation and to a State or federal NO_X mass reduction program that adopts the provisions of this part must meet the requirements of this part during the entire calendar year.

(2) The owner or operator of an affected unit subject to a State or federal NO_X mass reduction program that adopts the provisions of this part and that requires monitoring and reporting of hourly emissions on an annual basis must meet the requirements of this part during the entire calendar year.

(b) Ozone season monitoring requirements. The owner or operator of an affected unit that is not required to meet the requirements of this subpart on an annual basis under paragraph (a) of this section may either:

(1) Meet the requirements of this subpart on an annual basis; or

(2) Meet the requirements of this part during the ozone season, except as specified in paragraph (c) of this section.

(c) If the owner or operator of an affected unit chooses to meet the requirements of this subpart on less than an annual basis in accordance with paragraph (b)(2) of this section, then:

(1) The owner or operator of a unit that uses continuous emissions monitoring systems to meet any of the requirements of this subpart must perform recertification testing of all continuous emission monitoring systems under § 75.20(b). If the owner or operator has not successfully completed all recertification tests by the first hour of unit operation during the ozone season each year, the owner or operator must substitute for data following the procedures of § 75.20(b).

(2) The owner or operator is required to operate and maintain continuous emission monitoring systems and perform quality assurance and quality control procedures under § 75.21 and appendix B of this part each year from the time the continuous emission monitoring system is initially certified or is recertified under paragraph (c)(1) of this section through September 30. Records related to the quality assurance/quality control program must be kept in a form suitable for inspection on a year-round basis.

(3) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is required to operate or maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall count all quarters during the year when the fuel flowmeter is used, not just quarters in the ozone season. The owner or operator shall record and the designated representative shall report the number of quarters when a fuel is combusted for each fuel flowmeter.

(4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is only required to sample fuel during the ozone season, except that:

(i) The owner or operator of a diesel-fired unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.

(ii) The owner or operator of a diesel-fired unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.

(iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel oil or that performs oil sampling continuously must sample the fuel oil starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.

(5) The owner or operator is required to record and report the hourly data required by this subpart for the longer of:

(i) The period of time that the owner or operator of the unit is required to perform the quality assurance and quality control procedures of § 75.21 and appendix B of this part under paragraph (c)(2) of this section; or

(ii) The period of time of May 1 through September 30.

(6) The owner or operator shall use quality-assured data, in accordance with paragraph (c)(2) or (c)(3) of this section, in the substitute data procedures under subpart D of this part and section 2.4 of appendix D of this part.

(i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_X-diluent continuous emission monitoring system, a NO_X concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only data from periods when the monitors were quality assured under paragraph (c)(2) or (c)(3) of this section.

(ii) If the NO_X emission rate or NO_X concentration of the unit was consistently lower in the previous ozone season because the unit combusted a fuel that produces less NO_X than the fuel currently being combusted or because the unit's add-on emission controls are not operating properly, then the owner or operator shall not use the

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missing data procedures of §§ 75.31 through 75.33. Instead, the owner or operator shall substitute the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, from a NO_X-diluent continuous emission monitoring system, or the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, from a NO_X concentration monitoring system. The owner or operator shall substitute these maximum potential values for each hour of missing NO_X data, from completion of recertification testing until the earliest of:

(A) 720 quality-assured monitor operating hours after the completion of recertification testing (not to go beyond September 30 of that ozone season), or

(B) For a unit that changed fuels, the first hour when the unit combusts a fuel that produces the same or less NO_X than the fuel combusted in the previous ozone season, or

(C) For a unit with add-on emission controls that are not operating properly, the first hour when the add-on emission controls operate properly.

(7) The owner or operator of a unit with NO_X add-on emission controls or a unit capable of combusting more than one fuel shall keep records during ozone season in a form suitable for inspection to demonstrate that the typical NO_X emission rate or NO_X concentration during the prior ozone season(s) included in the missing data lookback period is representative of the ozone season in which missing data are substituted and that use of the missing data procedures will not systematically underestimate NO_X mass emissions. These records shall include:

(i) For units that can combust more than one fuel, the fuel or fuels combusted each hour; and

(ii) For units with add-on emission controls, the range of operating parameters for add-on emission controls, as described in § 75.34(a) and information for verifying proper operation of the add-on emission controls, as described in § 75.34(d).

(8) The designated representative shall certify with each quarterly report that NO_X emission rate values or NO_X concentration values substituted for missing data under subpart D of this part are calculated using only values from an ozone season, that substitute values measured during the prior ozone season(s) included in the missing data lookback period are representative of the ozone season in which missing data are substituted, and that NO_X emissions are not systematically underestimated.

(9) Units may qualify to use the low mass emission excepted monitoring methodology in § 75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 25 tons of NO_X per ozone season. The owner or operator of the unit shall meet the requirements of § 75.19, with the following exceptions:

(i) The phrase ‘‘50 tons of NO_X annually’’ shall be replaced by the phrase ‘‘25 tons of NO_X during the ozone season.’’

(ii) If any low mass emission unit fails to provide a demonstration that its ozone season NO_X mass emissions are less than 25 tons, than the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitoring using an acceptable methodology by May 1 of the following year.

(10) Units may qualify to use the optional NO_X mass emissions estimation protocol for gas-fired peaking units and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of peaking unit in § 72.2 of this part, except that the word ‘‘calender year’’ shall be replaced by the word ‘‘ozone season’’ and the word annual in the definition of the term ‘‘capacity factor’’ in § 72.2 of this part, shall be replaced by the word ‘‘ozone season’’.

§ 75.75 Additional ozone season calculation procedures for special circumstances.

(a) The owner or operator of a unit that is required to calculate ozone season heat input for purposes of providing data needed for determining allocations, shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the ozone season.

(b) The owner or operator of a unit that is required to determine ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing ozone season NO_X mass emissions(in lbs) determined in accordance with this subpart, by heat input determined in accordance with paragraph (a) of this section.

17. Section 3 of appendix A to part 75 is amended by revising the title of section 3.3.2 and by adding and reserving section 3.3.6, by adding new section 3.3.7 and by revising section 3.4.1 to read as follows:

APPENDIX A TO PART 75—SPECIFICATIONS AND TEST PROCEDURES

* * * * *

3. PERFORMANCE SPECIFICATIONS

* * * * *

3.3.2 RELATIVE ACCURACY FOR NO_X DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

* * * * *

3.3.6 [Reserved]

3.3.7 RELATIVE ACCURACY FOR NO_X CONCENTRATION MONITORING SYSTEMS

The following requirement applies only to NO_X concentration monitoring systems (i.e., NO_X pollutant concentration monitors) that are used to determine NO_X mass emissions, where the owner or operator elects to monitor and report NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system.

The relative accuracy for NO_X concentration monitoring systems shall not exceed 10.0 percent.

* * * * *

3.4.1 SO_2 POLLUTANT CONCENTRATION MONITORS, NO_X CONCENTRATION MONITORING SYSTEMS AND NO_X-DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

SO_2 pollutant concentration monitors and NO_X emission rate continuous emissions monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix. NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71, shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors, including those measuring an average SO_2 concentration of 250.0 ppm or less, and to all NO_X-diluent continuous emission monitoring systems, including those measuring an average NO_X emission rate of 0.20 lb/mmBtu or less.

* * * * *

18. Section 6 of appendix A to part 75 is amended by revising the first sentence of the introductory text of section 6.5 and by adding a new sentence after the first sentence, to read as follows:

* * * * *

6.5 Relative Accuracy and Bias Tests

Perform relative accuracy test audits for each CO_2 and SO_2 pollutant concentration monitor; each NO_X concentration monitoring system used to determine NO_X mass emissions; each O_2 monitor used to calculate heat input or CO_2 concentration; each SO_2- diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999; each flow monitor; and each NO_X-diluent continuous emission monitoring system. Perform relative accuracy test audits for each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), using the same general procedures as for CO_2 and

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SO_2 pollutant concentration monitors; however, use the reference methods for NO_X concentration listed in section 6.5.10 of this appendix. * * *

* * * * *

19. Section 7 of appendix A is amended by revising the introductory text of section 7.6 and by adding three sentences to the end of section 7.6.5 to read as follows:

* * * * *

7.6 Bias Test and Adjustment Factor

Test the relative accuracy test audit data sets for bias for SO_2 pollutant concentration monitors; flow monitors; NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71(a)(2); and NO_X-diluent continuous emission monitoring systems using the procedures outlined below.

* * * * *

7.6.5 Bias Adjustment

* * * In addition, use the adjusted NO_X concentration and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_X concentration and the flow rate when used to calculate NO_X mass emissions, as specified in subpart H of this part. Do not use an adjusted NO_X concentration value to calculate NO_X emission rate using Equations F–5 or F–6 of Appendix F of this part. When monitoring NO_X emission rate and heat input, use the adjusted NO_X emission rate and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_X emission rate and the heat input.

* * * * *

20. Appendix C to part 75 is amended by revising sections 2.1, 2.2.2, 2.2.3, 2.2.5, and 2.2.6 to read as follows:

APPENDIX C TO PART 75—MISSING DATA ESTIMATION PROCEDURES

* * * * *

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_X emission rate (in lb/mmBtu), and NO_X concentration data (in ppm) from NO_X concentration monitoring systems used to determine NO_X mass emissions.

2.2 Procedure

2.2.1 * * *

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71, for each hour of unit operation record a number, 1 through 10 (or 1 through 20 for flow at common stacks), that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71 and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_X data within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO_X emission rate, in lb/mmBtu, reported by a NO_X continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO_X pollutant concentration, in ppm, reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71.

2.2.3.10 The 90th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_X pollutant concentration, in ppm.

2.2.4 * * *

2.2.5 When a bias adjustment is necessary for the flow monitor or the NO_X continuous emission monitoring system (or the NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

* * * * *

21. Section 2 of appendix D to part 75 is amended by revising the introductory text of section 2.1.2 to read as follows:

APPENDIX D TO PART 75—OPTIONAL SO_2 EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

* * * * *

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program, except as provided in § 75.72(a) for units with a NO_X CEMS installed in a common stack or except as provided for units monitored with an excepted monitoring system under appendix E to this part. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

* * * * *

22. Section 8 of appendix F to part 75 is added to read as follows:

APPENDIX F TO PART 75—CONVERSION PROCEDURES

* * * * *

8. Procedures for NO_X Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program must use the procedures in section 8.1 to account for hourly NO_X mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_X mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_X mass emissions in lbs for the hour using hourly NO_X emission rate and heat input.

8.1.1 If both NO_X emission rate and heat input are monitored at the same unit or stack level (e.g, the NO_X emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{(NO_X)h} = E_{(NO_X)h} HI_h t_h \qquad \text{(Eq. F-24)}$$

where:

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

$E_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

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t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_X emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}} \qquad \text{(Eq. F-25)}$$

where:

HI_{CS} = Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS} = Common stack operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)(e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

Use the hourly heat input rate at the common stack level and the hourly average NO_X emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_X mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_X emission rate is only measured at one duct, use the NO_X emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_X mass emissions.

8.1.4 If a unit has multiple ducts and NO_X emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_X mass emissions.

8.2 If a unit calculates NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, calculate hourly NO_X mass rate during unit (or stack) operation, in lb/hr, using Equation F–1 or F–2 in this appendix (as applicable to the moisture basis of the monitors). When using Equation F–1 or F–2, replace ''SO_2'' with ''NO_X'' and replace the value of K with 1.194 x 10 ¥7 (lb NO_X/scf)/ppm. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

8.3 If a unit calculates NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, calculate NO_X mass emissions for the hour (lb) by multiplying the hourly NO_X mass emission rate during unit operation (lb/hr) by the unit operating time during the hour, as follows:

$$M_{(NO_X)_h} = E_h t_h \qquad \text{(Eq. F-26)}$$

Where:

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

E_h = Hourly NO_X mass emission rate during unit (or stack) operation, lb/hr, from section 8.2 of this appendix.

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the NO_X mass emission rate is monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO in $_X$ mass emissions, tons:

$$M_{(NO_X)_{time\ period}} = \frac{\sum_{h=1}^{p} M_{(NO_X)_h}}{2000} \qquad \text{(Eq. F-27)}$$

Where:

$M_{(NOx)\ time\ period}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.5 Specific provisions for monitoring NO_X mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_X mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_X mass reduction program:

8.5.1 The owner or operator may determine both NO_X emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_X mass emissions at the common stack.

8.5.2 The owner or operator may determine the NO_X emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_X mass emissions at each unit.

23. Part 96 is added to read as follows:

PART 96—NO_X Budget Trading Program for State Implementation Plans

Subpart A—NO_X Budget Trading Program General Provisions

Subpart B—Authorized Account Representative for NO_X Budget Sources

Subpart C—Permits

Subpart D—Compliance Certification

Subpart E—NO_X Allowance Allocations

Subpart F—NO_X Allowance Tracking System

Subpart G—NO_X Allowance Transfers

Subpart H—Monitoring and Reporting

Subpart I—Individual Unit Opt-ins

Subpart J—Mobile and Area Sources [Reserved]

Authority: 42 U.S.C. 7401, 7403, 7410, and 7601

Subpart A—NO_X Budget Trading Program General Provisions

§ 96.1 Purpose.

This part establishes general provisions and the applicability, permitting, allowance, excess emissions, monitoring, and opt-in provisions for the NO_X Budget Trading Program for State implementation plans as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor. The owner or operator of a unit, or any other person, shall comply with requirements of this part as a matter of federal law only to the extent a State that has jurisdiction over the unit incorporates by reference provisions of this part, or otherwise adopts such requirements of this part, and requires compliance, the State submits to the Administrator a State implementation plan including such adoption and such compliance requirement, and the Administrator approves the portion of the State implementation plan including such adoption and such compliance requirement. To the extent a State adopts requirements of this part, including at a minimum the requirements of subpart A (except for § 96.4(b)), subparts B through D, subpart F (except for § 96.55(c)), and subparts G and H of this part, the State authorizes the Administrator to assist the State in implementing the NO_X Budget Trading Program by carrying out the functions set forth for the Administrator in such requirements.

§ 96.2 Definitions.

The terms used in this part shall have the meanings set forth in this section as follows:

Account certificate of representation means the completed and signed submission required by subpart B of this part for certifying the designation of a NO_X authorized account representative for a NO_X Budget source or a group of identified NO_X Budget sources who is authorized to represent the owners and operators of such source or sources and of the NO_X Budget units at such source or sources with regard to matters under the NO_X Budget Trading Program.

Account number means the identification number given by the Administrator to each NO_X Allowance Tracking System account.

Acid Rain emissions limitation means, as defined in § 72.2 of this chapter, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the CAA.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means the determination by the permitting authority or the Administrator of the number of NO_X allowances to be initially credited to a NO_X Budget unit or an allocation set-aside.

Automated data acquisition and handling system or *DAHS* means that component of the CEMS, or other emissions monitoring system approved for use under subpart H of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart H of this part.

Boiler means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

CAA means the CAA, 42 U.S.C. 7401, *et seq.* , as amended by Pub. L. No. 101–549 (November 15, 1990).

Combined cycle system means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

Combustion turbine means an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

Commence commercial operation means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. Except as provided in § 96.5, for a unit that is a NO_X Budget unit under § 96.4 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in § 96.5 or subpart I of this part, for a unit that is not a NO_X Budget unit under § 96.4 on the date the unit commences commercial operation, the date the unit becomes a NO_X Budget unit under § 96.4 shall be the unit's date of commencement of commercial operation.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. Except as provided in § 96.5, for a unit that is a NO_X Budget unit under § 96.4 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in § 96.5 or subpart I of this part, for a unit that is not a NO_X Budget unit under § 96.4 on the date of commencement of operation, the date the unit becomes a NO_X Budget unit under § 96.4 shall be the unit's date of commencement of operation.

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means a NO_X Allowance Tracking System account, established by the Administrator for a NO_X Budget unit under subpart F of this part, in which the NO_X allowance allocations for the unit are initially recorded and in which are held NO_X allowances available for use by the unit for a control period for the purpose of meeting the unit's NO_X Budget emissions limitation.

Compliance certification means a submission to the permitting authority

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or the Administrator, as appropriate, that is required under subpart D of this part to report a NO_X Budget source's or a NO_X Budget unit's compliance or noncompliance with this part and that is signed by the NO_X authorized account representative in accordance with subpart B of this part.

Continuous emission monitoring system or *CEMS* means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes of the measured parameters, a permanent record of nitrogen oxides emissions, expressed in tons per hour for nitrogen oxides. The following systems are component parts included, consistent with part 75 of this chapter, in a continuous emission monitoring system:

(1) Flow monitor;

(2) Nitrogen oxides pollutant concentration monitors;

(3) Diluent gas monitor (oxygen or carbon dioxide) when such monitoring is required by subpart H of this part;

(4) A continuous moisture monitor when such monitoring is required by subpart H of this part; and

(5) An automated data acquisition and handling system.

Control period means the period beginning May 1 of a year and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the NO_X authorized account representative and as determined by the Administrator in accordance with subpart H of this part.

Energy Information Administration means the Energy Information Administration of the United States Department of Energy.

Excess emissions means any tonnage of nitrogen oxides emitted by a NO_X Budget unit during a control period that exceeds the NO_X Budget emissions limitation for the unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means, with regard to a unit:

(1) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a unit had no heat input starting in 1995, during the last year of operation of the unit prior to 1995; or

(2) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the unit shall be ''fossil fuel-fired'' as of the date, during such year, on which the unit begins combusting fossil fuel.

General account means a NO_X Allowance Tracking System account, established under subpart F of this part, that is not a compliance account or an overdraft account.

Generator means a device that produces electricity.

Heat input means the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) and the fuel feed rate into a combustion device (in mass of fuel/time), as measured, recorded, and reported to the Administrator by the NO_X authorized account representative and as determined by the Administrator in accordance with subpart H of this part, and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Life-of-the-unit, firm power contractual arrange ment means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy from any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the ability of a unit to combust a stated maximum amount of fuel per hour on a steady state basis, as determined by the physical design and physical characteristics of the unit.

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flowrate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

Maximum potential NO_X emission rate means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential nitrogen oxides concentration as defined in section 2 of appendix A of part 75 of this chapter, and either the maximum oxygen concentration (in percent O_2) or the minimum carbon dioxide concentration (in percent CO_2), under all operating conditions of the unit except for unit start up, shutdown, and upsets.

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

Monitoring system means any monitoring system that meets the requirements of subpart H of this part, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

Most stringent State or Federal NO_X emissions limitation means, with regard to a NO_X Budget opt-in source, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.

Non-title V permit means a federally enforceable permit administered by the permitting authority pursuant to the CAA and regulatory authority under the CAA, other than title V of the CAA and part 70 or 71 of this chapter.

NO_X allowance means an authorization by the permitting authority or the Administrator under the NO_X Budget Trading Program to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter.

NO_X allowance deduction or *deduct NO_X allowances* means the permanent withdrawal of NO_X allowances by the

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Administrator from a NO_X Allowance Tracking System compliance account or overdraft account to account for the number of tons of NO_X emissions from a NO_X Budget unit for a control period, determined in accordance with subpart H of this part, or for any other allowance surrender obligation under this part.

NO_X allowances held or *hold NO_X allowances* means the NO_X allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts F and G of this part, in a NO_X Allowance Tracking System account.

NO_X Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of NO_X allowances under the NO_X Budget Trading Program.

NO_X Allowance Tracking System account means an account in the NO_X Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of NO_X allowances.

NO_X allowance transfer deadline means midnight of November 30 or, if November 30 is not a business day, midnight of the first business day thereafter and is the deadline by which NO_X allowances may be submitted for recordation in a NO_X Budget unit's compliance account, or the overdraft account of the source where the unit is located, in order to meet the unit's NO_X Budget emissions limitation for the control period immediately preceding such deadline.

NO_X authorized account representative means, for a NO_X Budget source or NO_X Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all NO_X Budget units at the source, in accordance with subpart B of this part, to represent and legally bind each owner and operator in matters pertaining to the NO_X Budget Trading Program or, for a general account, the natural person who is authorized, in accordance with subpart F of this part, to transfer or otherwise dispose of NO_X allowances held in the general account.

NO_X Budget emissions limitation means, for a NO_X Budget unit, the tonnage equivalent of the NO_X allowances available for compliance deduction for the unit and for a control period under § 96.54(a) and (b), adjusted by any deductions of such NO_X allowances to account for actual utilization under § 96.42(e) for the control period or to account for excess emissions for a prior control period under § 96.54(d) or to account for withdrawal from the NO_X Budget Program, or for a change in regulatory status, for a NO_X Budget opt-in source under § 96.86 or § 96.87.

NO_X Budget opt-in permit means a NO_X Budget permit covering a NO_X Budget opt-in source.

NO_X Budget opt-in source means a unit that has been elected to become a NO_X Budget unit under the NO_X Budget Trading Program and whose NO_X Budget opt-in permit has been issued and is in effect under subpart I of this part.

NO_X Budget permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under this part, including any permit revisions, specifying the NO_X Budget Trading Program requirements applicable to a NO_X Budget source, to each NO_X Budget unit at the NO_X Budget source, and to the owners and operators and the NO_X authorized account representative of the NO_X Budget source and each NO_X Budget unit.

NO_X Budget source means a source that includes one or more NO_X Budget units.

NO_X Budget Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program established in accordance with this part and pursuant to § 51.121 of this chapter, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

NO_X Budget unit means a unit that is subject to the NO_X Budget Trading Program emissions limitation under § 96.4 or § 96.80.

Operating means, with regard to a unit under §§ 96.22(d)(2) and 96.80, having documented heat input for more than 876 hours in the 6 months immediately preceding the submission of an application for an initial NO_X Budget permit under § 96.83(a).

Operator means any person who operates, controls, or supervises a NO_X Budget unit, a NO_X Budget source, or unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Opt-in means to be elected to become a NO_X Budget unit under the NO_X Budget Trading Program through a final, effective NO_X Budget opt-in permit under subpart I of this part.

Overdraft account means the NO_X Allowance Tracking System account, established by the Administrator under subpart F of this part, for each NO_X Budget source where there are two or more NO_X Budget units.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a NO_X Budget unit or in a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(2) Any holder of a leasehold interest in a NO_X Budget unit or in a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(3) Any purchaser of power from a NO_X Budget unit or from a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn under a life-of-the-unit, firm power contractual arrangement. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the NO_X Budget unit or the unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(4) With respect to any general account, any person who has an ownership interest with respect to the NO_X allowances held in the general account and who is subject to the binding agreement for the NO_X authorized account representative to represent that person's ownership interest with respect to NO_X allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the NO_X Budget Trading Program in accordance with subpart C of this part.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to NO_X allowances, the movement of NO_X allowances by the Administrator from one NO_X Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

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Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NO_X allowances, the unique identification number assigned to each NO_X allowance by the Administrator, under § 96.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the CAA. For purposes of section 502(c) of the CAA, a ''source,'' including a ''source'' with multiple units, shall be considered a single ''facility.''

State means one of the 48 contiguous States and the District of Columbia specified in § 51.121 of this chapter, or any non-federal authority in or including such States or the District of Columbia (including local agencies, and Statewide agencies) or any eligible Indian tribe in an area of such State or the District of Columbia, that adopts a NO_X Budget Trading Program pursuant to § 51.121 of this chapter. To the extent a State incorporates by reference the provisions of this part, the term ''State'' shall mean the incorporating State. The term ''State'' shall have its conventional meaning where such meaning is clear from the context.

State trading program budget means the total number of NO_X tons apportioned to all NO_X Budget units in a given State, in accordance with the NO_X Budget Trading Program, for use in a given control period.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any ''submission,'' ''service,'' or ''mailing'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Ton or tonnage means any ''short ton'' (i.e., 2,000 pounds). For the purpose of determining compliance with the NO_X Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.

Unit means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit load means the total (i.e., gross) output of a unit in any control period (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) produced by the unit, including generation for use within the plant; or

(2) In the case of a unit that uses heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit, including steam for use by the unit.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means any hour (or fraction of an hour) during which a unit combusts any fuel.

Utilization means the heat input (expressed in mmBtu/time) for a unit. The unit's total heat input for the control period in each year will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

§ 96.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
hr—hour.
Kwh—kilowatt hour. lb—pounds.
mmBtu—million Btu. MWe—megawatt electrical. ton—2000 pounds.
CO_2—carbon dioxide. NO_X—nitrogen oxides. O_2—oxygen.

§ 96.4 Applicability.

(a) The following units in a State shall be NO_X Budget units, and any source that includes one or more such units shall be a NO_X Budget source, subject to the requirements of this part:

(1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

(2) Any unit that is not a unit under paragraph (a) of this section and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding paragraph (a) of this section, a unit under paragraph (a) of this section shall be subject only to the requirements of this paragraph (b) if the unit has a federally enforceable permit that meets the requirements of paragraph (b)(1) of this section and restricts the unit to burning only natural gas or fuel oil during a control period in 2003 or later and each control period thereafter and restricts the unit's operating hours during each such control period to the number of hours (determined in accordance with paragraph (b)(1)(ii) and (iii) of this section) that limits the unit's potential NO_X mass emissions for the control period to 25 tons or less. Notwithstanding paragraph (a) of this section, starting with the effective date of such federally enforceable permit, the unit shall not be a NO_X Budget unit.

(1) For each control period under paragraph (b) of this section, the federally enforceable permit must:

(i) Restrict the unit to burning only natural gas or fuel oil.

(ii) Restrict the unit's operating hours to the number calculated by dividing 25 tons of potential NO_X mass emissions by the unit's maximum potential hourly NO_X mass emissions.

(iii) Require that the unit's potential NO_X mass emissions shall be calculated as follows:

(A) Select the default NO_X emission rate in Table 2 of § 75.19 of this chapter that would otherwise be applicable assuming that the unit burns only the type of fuel (i.e., only natural gas or only fuel oil) that has the highest default NO_X emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in paragraph (b)(1)(i) of this section; and

(B) Multiply the default NO_X emission rate under paragraph (b)(1)(iii)(A) of this section by the unit's maximum rated hourly heat input. The owner or operator of the unit may petition the permitting authority to use a lower value for the unit's maximum rated hourly heat input than the value as defined under § 96.2. The permitting authority may approve such lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that such lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(iv) Require that the owner or operator of the unit shall retain at the source that includes the unit, for 5 years, records demonstrating that the operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met.

(v) Require that the owner or operator of the unit shall report the unit's hours of operation (treating any partial hour of operation as a whole hour of operation) during each control period to the permitting authority by November 1 of each year for which the unit is subject to the federally enforceable permit.

(2) The permitting authority that issues the federally enforceable permit with the fuel use restriction under paragraph (b)(1)(i) and the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section will notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority includes such restrictions. The permitting authority will also notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority is revised to remove any such restriction, whose federally enforceable permit issued by the permitting authority includes any such restriction that is no longer applicable, or which does not comply with any such restriction.

(3) If, for any control period under paragraph (b) of this section, the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section is removed from the unit's federally enforceable permit or otherwise becomes no longer applicable or if, for any such control period, the unit does not comply with the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section, the unit shall be a NO_X Budget unit, subject to the requirements of this part. Such unit shall be treated as commencing operation and, for a unit under paragraph (a)(1) of this section, commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours restriction.

§ 96.5 Retired unit exemption.

(a) This section applies to any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired.

(b)(1) Any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired shall be exempt from the NO_X Budget Trading Program, except for the provisions of this section, §§ 96.2, 96.3, 96.4, 96.7 and subparts E, F, and G of this part.

(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NO_X authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NO_X Budget permit for the unit. A copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the permitting authority) that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) *Special provisions.* (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart E of this part.

(2)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(ii) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a non-title V permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(3) The owners and operators and, to the extent applicable, the NO_X authorized account representative of a unit exempt under this section shall comply with the requirements of the NO_X Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit that is exempt under this section is not eligible to be a NO_X Budget opt-in source under subpart I of this part.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) *Loss of exemption.* (i) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(A) The date on which the NO_X authorized account representative submits a NO_X Budget permit application under paragraph (c)(2) of this section; or

(B) The date on which the NO_X authorized account representative is required under paragraph (c)(2) of this section to submit a NO_X Budget permit application.

(ii) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

§ 96.6 Standard requirements.

(a) *Permit Requirements.* (1) The NO_X authorized account representative of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NO_X Budget permit application under § 96.22 in accordance

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with the deadlines specified in § 96.21(b) and (c);

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a NO_X Budget permit application and issue or deny a NO_X Budget permit.

(2) The owners and operators of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall have a NO_X Budget permit issued by the permitting authority and operate the unit in compliance with such NO_X Budget permit.

(3) The owners and operators of a NO_X Budget source that is not otherwise required to have a federally enforceable permit are not required to submit a NO_X Budget permit application, and to have a NO_X Budget permit, under subpart C of this part for such NO_X Budget source.

(b) *Monitoring requirements.* (1) The owners and operators and, to the extent applicable, the NO_X authorized account representative of each NO_X Budget source and each NO_X Budget unit at the source shall comply with the monitoring requirements of subpart H of this part.

(2) The emissions measurements recorded and reported in accordance with subpart H of this part shall be used to determine compliance by the unit with the NO_X Budget emissions limitation under paragraph (c) of this section.

(c) *Nitrogen oxides requirements.* (1) The owners and operators of each NO_X Budget source and each NO_X Budget unit at the source shall hold NO_X allowances available for compliance deductions under § 96.54, as of the NO_X allowance transfer deadline, in the unit's compliance account and the source's overdraft account in an amount not less than the total NO_X emissions for the control period from the unit, as determined in accordance with subpart H of this part, plus any amount necessary to account for actual utilization under § 96.42(e) for the control period.

(2) Each ton of nitrogen oxides emitted in excess of the NO_X Budget emissions limitation shall constitute a separate violation of this part, the CAA, and applicable State law.

(3) A NO_X Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2003 or the date on which the unit commences operation.

(4) NO_X allowances shall be held in, deducted from, or transferred among NO_X Allowance Tracking System accounts in accordance with subparts E, F, G, and I of this part.

(5) A NO_X allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) of this section, for a control period in a year prior to the year for which the NO_X allowance was allocated.

(6) A NO_X allowance allocated by the permitting authority or the Administrator under the NO_X Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the NO_X Budget Trading Program. No provision of the NO_X Budget Trading Program, the NO_X Budget permit application, the NO_X Budget permit, or an exemption under § 96.5 and no provision of law shall be construed to limit the authority of the United States or the State to terminate or limit such authorization.

(7) A NO_X allowance allocated by the permitting authority or the Administrator under the NO_X Budget Trading Program does not constitute a property right.

(8) Upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from a NO_X Budget unit's compliance account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, any NO_X Budget permit of the NO_X Budget unit by operation of law without any further review.

(d) *Excess emissions requirements.* (1) The owners and operators of a NO_X Budget unit that has excess emissions in any control period shall:

(i) Surrender the NO_X allowances required for deduction under § 96.54(d)(1); and

(ii) Pay any fine, penalty, or assessment or comply with any other remedy imposed under § 96.54(d)(3).

(e) Recordkeeping and Reporting requirements.

(1) Unless otherwise provided, the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The account certificate of representation for the NO_X authorized account representative for the source and each NO_X Budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with § 96.13; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new account certificate of representation changing the NO_X authorized account representative.

(ii) All emissions monitoring information, in accordance with subpart H of this part; provided that to the extent that subpart H of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_X Budget Trading Program.

(iv) Copies of all documents used to complete a NO_X Budget permit application and any other submission under the NO_X Budget Trading Program or to demonstrate compliance with the requirements of the NO_X Budget Trading Program.

(2) The NO_X authorized account representative of a NO_X Budget source and each NO_X Budget unit at the source shall submit the reports and compliance certifications required under the NO_X Budget Trading Program, including those under subparts D, H, or I of this part.

(f) *Liability.* (1) Any person who knowingly violates any requirement or prohibition of the NO_X Budget Trading Program, a NO_X Budget permit, or an exemption under § 96.5 shall be subject to enforcement pursuant to applicable State or Federal law.

(2) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_X Budget Trading Program shall be subject to criminal enforcement pursuant to the applicable State or Federal law.

(3) No permit revision shall excuse any violation of the requirements of the NO_X Budget Trading Program that occurs prior to the date that the revision takes effect.

(4) Each NO_X Budget source and each NO_X Budget unit shall meet the requirements of the NO_X Budget Trading Program.

(5) Any provision of the NO_X Budget Trading Program that applies to a NO_X Budget source (including a provision applicable to the NO_X authorized account representative of a NO_X Budget source) shall also apply to the owners and operators of such source and of the NO_X Budget units at the source.

(6) Any provision of the NO_X Budget Trading Program that applies to a NO_X Budget unit (including a provision applicable to the NO_X authorized

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account representative of a NO_X budget unit) shall also apply to the owners and operators of such unit. Except with regard to the requirements applicable to units with a common stack under subpart H of this part, the owners and operators and the NO_X authorized account representative of one NO_X Budget unit shall not be liable for any violation by any other NO_X Budget unit of which they are not owners or operators or the NO_X authorized account representative and that is located at a source of which they are not owners or operators or the NO_X authorized account representative.

(g) *Effect on other authorities.* No provision of the NO_X Budget Trading Program, a NO_X Budget permit application, a NO_X Budget permit, or an exemption under § 96.5 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NO_X authorized account representative of a NO_X Budget source or NO_X Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the CAA.

§ 96.7 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the NO_X Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the NO_X Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the NO_X Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

Subpart B—NO_X Authorized Account Representative for NO_X Budget Sources

§ 96.10 Authorization and responsibilities of the NO_X authorized account representative.

(a) Except as provided under § 96.11, each NO_X Budget source, including all NO_X Budget units at the source, shall have one and only one NO_X authorized account representative, with regard to all matters under the NO_X Budget Trading Program concerning the source or any NO_X Budget unit at the source.

(b) The NO_X authorized account representative of the NO_X Budget source shall be selected by an agreement binding on the owners and operators of the source and all NO_X Budget units at the source.

(c) Upon receipt by the Administrator of a complete account certificate of representation under § 96.13, the NO_X authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the NO_X Budget source represented and each NO_X Budget unit at the source in all matters pertaining to the NO_X Budget Trading Program, not withstanding any agreement between the NO_X authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the NO_X authorized account representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No NO_X Budget permit shall be issued, and no NO_X Allowance Tracking System account shall be established for a NO_X Budget unit at a source, until the Administrator has received a complete account certificate of representation under § 96.13 for a NO_X authorized account representative of the source and the NO_X Budget units at the source.

(e)(1) Each submission under the NO_X Budget Trading Program shall be submitted, signed, and certified by the NO_X authorized account representative for each NO_X Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the NO_X authorized account representative: ''I am authorized to make this submission on behalf of the owners and operators of the NO_X Budget sources or NO_X Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a NO_X Budget source or a NO_X Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.11 Alternate NO_X authorized account representative.

(a) An account certificate of representation may designate one and only one alternate NO_X authorized account representative who may act on behalf of the NO_X authorized account representative. The agreement by which the alternate NO_X authorized account representative is selected shall include a procedure for authorizing the alternate NO_X authorized account representative to act in lieu of the NO_X authorized account representative.

(b) Upon receipt by the Administrator of a complete account certificate of representation under § 96.13, any representation, action, inaction, or submission by the alternate NO_X authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO_X authorized account representative.

(c) Except in this section and §§ 96.10(a), 96.12, 96.13, and 96.51, whenever the term ''NO_X authorized account representative'' is used in this part, the term shall be construed to include the alternate NO_X authorized account representative.

§ 96.12 Changing the NO_X authorized account representative and the alternate NO_X authorized account representative; changes in the owners and operators.

(a) *Changing the NO_X authorized account representative.* The NO_X authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under § 96.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NO_X authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(b) Changing the alternate NO_X authorized account representative. The alternate NO_X authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under § 96.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NO_X authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new alternate NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(c) Changes in the owners and operators. (1) In the event a new owner or operator of a NO_X Budget source or a NO_X Budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the permitting authority or the Administrator, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a NO_X Budget source or a NO_X Budget unit, including the addition of a new owner or operator, the NO_X authorized account representative or alternate NO_X authorized account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

§ 96.13 Account certificate of representation.

(a) A complete account certificate of representation for a NO_X authorized account representative or an alternate NO_X authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NO_X Budget source and each NO_X Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative.

(3) A list of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source.

(4) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: ''I certify that I was selected as the NO_X authorized account representative or alternate NO_X authorized account representative, as applicable, by an agreement binding on the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit.''

(5) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.14 Objections concerning the NO_X authorized account representative.

(a) Once a complete account certificate of representation under § 96.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under § 96.13 is received by the Administrator.

(b) Except as provided in § 96.12(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO_X Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO_X authorized account representative, including private legal disputes concerning the proceeds of NO_X allowance transfers.

Subpart C—Permits

§ 96.20 General NO_X Budget trading program permit requirements.

(a) For each NO_X Budget source required to have a federally enforceable permit, such permit shall include a NO_X Budget permit administered by the permitting authority.

(1) For NO_X Budget sources required to have a title V operating permit, the NO_X Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such title V operating permits regulations shall include, but are not limited to, those provisions addressing operating permit applications, operating permit application shield, operating permit duration, operating permit shield, operating permit issuance, operating permit revision and reopening, public participation, State review, and review by the Administrator.

(2) For NO_X Budget sources required to have a non-title V permit, the NO_X Budget portion of the non-title V permit shall be administered in accordance with the permitting authority's regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such non-title V permits regulations may include, but are not limited to, provisions addressing permit applications, permit application shield, permit duration, permit shield, permit issuance, permit revision and reopening, public participation, State review, and review by the Administrator.

(b) Each NO_X Budget permit (including a draft or proposed NO_X Budget permit, if applicable) shall contain all applicable NO_X Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§ 96.21 Submission of NO_X Budget permit applications.

(a) *Duty to apply.* The NO_X authorized account representative of any NO_X Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO_X Budget permit application under § 96.22 by the applicable deadline in paragraph (b) of this section.

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(b)(1) For NO_X Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(2) For NO_X Budget sources required to have a non-title V permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non- title V permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(c) *Duty to reapply.* (1) For a NO_X Budget source required to have a title V operating permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(2) For a NO_X Budget source required to have a non-title V permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's non-title V permits regulations addressing permit renewal.

§ 96.22 Information requirements for NO_X Budget permit applications.

A complete NO_X Budget permit application shall include the following elements concerning the NO_X Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the NO_X Budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration, if applicable;

(b) Identification of each NO_X Budget unit at the NO_X Budget source and whether it is a NO_X Budget unit under § 96.4 or under subpart I of this part;

(c) The standard requirements under § 96.6; and

(d) For each NO_X Budget opt-in unit at the NO_X Budget source, the following certification statements by the NO_X authorized account representative:

(1) ''I certify that each unit for which this permit application is submitted under subpart I of this part is not a NO_X Budget unit under 40 CFR 96.4 and is not covered by a retired unit exemption under 40 CFR 96.5 that is in effect.''

(2) If the application is for an initial NO_X Budget opt-in permit, ''I certify that each unit for which this permit application is submitted under subpart I is currently operating, as that term is defined under 40 CFR 96.2.''

§ 96.23 NO_X Budget permit contents.

(a) Each NO_X Budget permit (including any draft or proposed NO_X Budget permit, if applicable) will contain, in a format prescribed by the permitting authority, all elements required for a complete NO_X Budget permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subparts F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from the compliance accounts of the NO_X Budget units covered by the permit or the overdraft account of the NO_X Budget source covered by the permit.

§ 96.24 Effective date of initial NO_X Budget permit.

The initial NO_X Budget permit covering a NO_X Budget unit for which a complete NO_X Budget permit application is timely submitted under § 96.21(b) shall become effective by the later of:

(a) May 1, 2003;

(b) May 1 of the year in which the NO_X Budget unit commences operation, if the unit commences operation on or before May 1 of that year;

(c) The date on which the NO_X Budget unit commences operation, if the unit commences operation during a control period; or

(d) May 1 of the year following the year in which the NO_X Budget unit commences operation, if the unit commences operation on or after October 1 of the year.

§ 96.25 NO_X Budget permit revisions.

(a) For a NO_X Budget source with a title V operating permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

(b) For a NO_X Budget source with a non-title V permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's non-title V permits regulations addressing permit revisions.

Subpart D—Compliance Certification

§ 96.30 Compliance certification report.

(a) *Applicability and deadline.* For each control period in which one or more NO_X Budget units at a source are subject to the NO_X Budget emissions limitation, the NO_X authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) *Contents of report.* The NO_X authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO_X Budget emissions limitation for the control period covered by the report:

(1) Identification of each NO_X Budget unit;

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(2) At the NO_X authorized account representative's option, the serial numbers of the NO_X allowances that are to be deducted from each unit's compliance account under § 96.54 for the control period;

(3) At the NO_X authorized account representative's option, for units sharing a common stack and having NO_X emissions that are not monitored separately or apportioned in accordance with subpart H of this part, the percentage of allowances that is to be deducted from each unit's compliance account under § 96.54(e); and

(4) The compliance certification under paragraph (c) of this section.

(c) *Compliance certification.* In the compliance certification report under paragraph (a) of this section, the NO_X authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NO_X Budget units at the source in compliance with the NO_X Budget Trading Program, whether each NO_X Budget unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the NO_X Budget Trading Program applicable to the unit, including:

(1) Whether the unit was operated in compliance with the NO_X Budget emissions limitation;

(2) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute NO_X emissions to the unit, in accordance with subpart H of this part;

(3) Whether all the NO_X emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with subpart H of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions has been made;

(4) Whether the facts that form the basis for certification under subpart H of this part of each monitor at the unit or a group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under subpart H of this part, if any, has changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 96.31 Permitting authority's and Administrator's action on compliance certifications.

(a) The permitting authority or the Administrator may review and conduct independent audits concerning any compliance certification or any other submission under the NO_X Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

(b) The Administrator may deduct NO_X allowances from or transfer NO_X allowances to a unit's compliance account or a source's overdraft account based on the information in the compliance certifications or other submissions, as adjusted under paragraph (a) of this section.

Subpart E—NO_X Allowance Allocations

§ 96.40 State trading program budget.

The State trading program budget allocated by the permitting authority under § 96.42 for a control period will equal the total number of tons of NO_X emissions apportioned to the NO_X Budget units under § 96.4 in the State for the control period, as determined by the applicable, approved State implementation plan.

§ 96.41 Timing requirements for NO_X allowance allocations.

(a) By September 30, 1999, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for the control periods in 2003, 2004, and 2005.

(b) By April 1, 2003 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for the control period in the year that is three years after the year of the applicable deadline for submission under this paragraph (b). If the permitting authority fails to submit to the Administrator the NO_X allowance allocations in accordance with this paragraph (b), the Administrator will allocate, for the applicable control period, the same number of NO_X allowances as were allocated for the preceding control period.

(c) By April 1, 2004 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for any NO_X allowances remaining in the allocation set-aside for the prior control period.

§ 96.42 NO_X allowance allocations.

(a)(1) The heat input (in mmBtu) used for calculating NO_X allowance allocations for each NO_X Budget unit under § 96.4 will be:

(i) For a NO_X allowance allocation under § 96.41(a), the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996, and 1997 if the unit is under § 96.4(a)(1) or the control period in 1995 if the unit is under § 96.4(a)(2); and

(ii) For a NO_X allowance allocation under § 96.41(b), the unit's heat input for the control period in the year that is four years before the year for which the NO_X allocation is being calculated.

(2) The unit's total heat input for the control period in each year specified under paragraph (a)(1) of this section will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(b) For each control period under § 96.41, the permitting authority will allocate to all NO_X Budget units under § 96.4(a)(1) in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO_X allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the tons of NO_X emissions in the State trading program budget apportioned to electric generating units under § 96.40 in accordance with the following procedures:

(1) The permitting authority will allocate NO_X allowances to each NO_X Budget unit under § 96.4(a)(1) in an amount equaling 0.15 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, rounded to the nearest whole NO_X allowance as appropriate.

(2) If the initial total number of NO_X allowances allocated to all NO_X Budget units under § 96.4(a)(1) in the State for a control period under paragraph (b)(1) of this section does not equal 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program

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budget apportioned to electric generating units, the permitting authority will adjust the total number of NO_X allowances allocated to all such NO_X Budget units for the control period under paragraph (b)(1) of this section so that the total number of NO_X allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to electric generating units. This adjustment will be made by: multiplying each unit's allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to electric generating units divided by the total number of NO_X allowances allocated under paragraph (b)(1) of this section, and rounding to the nearest whole NO_X allowance as appropriate.

(c) For each control period under § 96.41, the permitting authority will allocate to all NO_X Budget units under § 96.4(a)(2) in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO_X allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units under § 96.40 in accordance with the following procedures:

(1) The permitting authority will allocate NO_X allowances to each NO_X Budget unit under § 96.4(a)(2) in an amount equaling 0.17 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, rounded to the nearest whole NO_X allowance as appropriate.

(2) If the initial total number of NO_X allowances allocated to all NO_X Budget units under § 96.4(a)(2) in the State for a control period under paragraph (c)(1) of this section does not equal 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units, the permitting authority will adjust the total number of NO_X allowances allocated to all such NO_X Budget units for the control period under paragraph (c)(1) of this section so that the total number of NO_X allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units. This adjustment will be made by: multiplying each unit's allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units divided by the total number of NO_X allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole NO_X allowance as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NO_X allowances to NO_X Budget units under § 96.4 in the State that commenced operation, or is projected to commence operation, on or after May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NO_X allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NO_X emissions in the State trading program budget under § 96.40, rounded to the nearest whole NO_X allowance as appropriate.

(2) The NO_X authorized account representative of a NO_X Budget unit under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NO_X allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the NO_X Budget unit commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. The NO_X allowance allocation request must be submitted prior to May 1 of the first control period for which the NO_X allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the NO_X Budget unit.

(3) In a NO_X allowance allocation request under paragraph (d)(2) of this section, the NO_X authorized account representative for units under § 96.4(a)(1) may request for a control period NO_X allowances in an amount that does not exceed 0.15 lb/mmBtu multiplied by the NO_X Budget unit's maximum design heat input (in mmBtu/ hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(4) In a NO_X allowance allocation request under paragraph (d)(2) of this section, the NO_X authorized account representative for units under § 96.4(a)(2) may request for a control period NO_X allowances in an amount that does not exceed 0.17 lb/mmBtu multiplied by the NO_X Budget unit's maximum design heat input (in mmBtu/ hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(5) The permitting authority will review, and allocate NO_X allowances pursuant to, each NO_X allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NO_X allowance allocation request, the permitting authority will determine whether, and will make any necessary adjustments to the request to ensure that, for units under § 96.4(a)(1), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for units under § 96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NO_X allowances are requested has an amount of NO_X allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NO_X allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the NO_X Budget unit.

(iii) If the allocation set-aside for the control period for which NO_X allowances are requested has a smaller amount of NO_X allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NO_X allowances in the allocation set-aside to the NO_X Budget unit.

(iv) Once an allocation set-aside for a control period has been depleted of all NO_X allowances, the permitting authority will deny, and will not allocate any NO_X allowances pursuant to, any NO_X allowance allocation request under which NO_X allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NO_X allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NO_X authorized account representative that submitted the request and the Administrator of the number of NO_X

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allowances (if any) allocated for the control period to the NO_X Budget unit.

(e) For a NO_X Budget unit that is allocated NO_X allowances under paragraph (d) of this section for a control period, the Administrator will deduct NO_X allowances under § 96.54(b) or (e) to account for the actual utilization of the unit during the control period. The Administrator will calculate the number of NO_X allowances to be deducted to account for the unit's actual utilization using the following formulas and rounding to the nearest whole NO_X allowance as appropriate, provided that the number of NO_X allowances to be deducted shall be zero if the number calculated is less than zero:

NO_X allowances deducted for actual utilization for units under § 96.4(a)(1) = (Unit's NO_X allowances allocated for control period) ¥(Unit's actual control period utilization × 0.15 lb/mmBtu); and

NO_X allowances deducted for actual utilization for units under § 96.4(a)(2) = (Unit's NO_X allowances allocated for control period) ¥(Unit's actual control period utilization × 0.17 lb/mmBtu)

Where:

''Unit's NO_X allowances allocated for control period'' is the number of NO_X allowances allocated to the unit for the control period under paragraph (d) of this section; and

''Unit's actual control period utilization'' is the utilization (in mmBtu), as defined in § 96.2, of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NO_X allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NO_X allowances to the NO_X Budget units in the State using the following formula and rounding to the nearest whole NO_X allowance as appropriate:

Unit's share of NO_X allowances remaining in allocation set-aside = Total NO_X allowances remaining in allocation set- aside × (Unit's NO_X allowance allocation ÷ (State trading program budget excluding allocation set-aside)

Where:

''Total NO_X allowances remaining in allocation set-aside'' is the total number of NO_X allowances remaining in the allocation set-aside for the control period to which the allocation set-aside applies;

''Unit's NO_X allowance allocation'' is the number of NO_X allowances allocated under paragraph (b) or (c) of this section to the unit for the control period to which the allocation set-aside applies; and

''State trading program budget excluding allocation set-aside'' is the State trading program budget under § 96.40 for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole NO_X allowance as appropriate.

Subpart F—NO_X Allowance Tracking System

§ 96.50 NO_X Allowance Tracking System accounts.

(a) Nature and function of compliance accounts and overdraft accounts. Consistent with § 96.51(a), the Administrator will establish one compliance account for each NO_X Budget unit and one overdraft account for each source with one or more NO_X Budget units. Allocations of NO_X allowances pursuant to subpart E of this part or § 96.88 and deductions or transfers of NO_X allowances pursuant to § 96.31, § 96.54, § 96.56, subpart G of this part, or subpart I of this part will be recorded in the compliance accounts or overdraft accounts in accordance with this subpart.

(b) Nature and function of general accounts. Consistent with § 96.51(b), the Administrator will establish, upon request, a general account for any person. Transfers of allowances pursuant to subpart G of this part will be recorded in the general account in accordance with this subpart.

§ 96.51 Establishment of accounts.

(a) Compliance accounts and overdraft accounts. Upon receipt of a complete account certificate of representation under § 96.13, the Administrator will establish:

(1) A compliance account for each NO_X Budget unit for which the account certificate of representation was submitted; and

(2) An overdraft account for each source for which the account certificate of representation was submitted and that has two or more NO_X Budget units.

(b) *General accounts.* (1) Any person may apply to open a general account for the purpose of holding and transferring allowances. A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(i) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative;

(ii) At the option of the NO_X authorized account representative, organization name and type of organization;

(iii) A list of all persons subject to a binding agreement for the NO_X authorized account representative or any alternate NO_X authorized account representative to represent their ownership interest with respect to the allowances held in the general account;

(iv) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: ''I certify that I was selected as the NO_X authorized account representative or the NO_X alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(v) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(vi) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(i) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(ii) The NO_X authorized account representative and any alternate NO_X authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to NO_X allowances held in the general account in all matters pertaining to the NO_X Budget Trading Program, not withstanding any agreement between the NO_X authorized account representative or any alternate NO_X authorized account representative and such person. Any such person shall be bound by any order or decision issued to the NO_X authorized account representative or any alternate NO_X authorized account representative by

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the Administrator or a court regarding the general account.

(iii) Each submission concerning the general account shall be submitted, signed, and certified by the NO_X authorized account representative or any alternate NO_X authorized account representative for the persons having an ownership interest with respect to NO_X allowances held in the general account. Each such submission shall include the following certification statement by the NO_X authorized account representative or any alternate NO_X authorized account representative any: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the NO_X allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iv) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(iii) of this section.

(3)(i) An application for a general account may designate one and only one NO_X authorized account representative and one and only one alternate NO_X authorized account representative who may act on behalf of the NO_X authorized account representative. The agreement by which the alternate NO_X authorized account representative is selected shall include a procedure for authorizing the alternate NO_X authorized account representative to act in lieu of the NO_X authorized account representative.

(ii) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, any representation, action, inaction, or submission by any alternate NO_X authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO_X authorized account representative.

(4)(i) The NO_X authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NO_X authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new NO_X authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.

(ii) The alternate NO_X authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NO_X authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate NO_X authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to NO_X allowances in the general account is not included in the list of such persons in the account certificate of representation, such new person shall be deemed to be subject to and bound by the account certificate of representation, the representation, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the Administrator, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to NO_X allowances in the general account, including the addition of persons, the NO_X authorized account representative or any alternate NO_X authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the NO_X allowances in the general account to include the change.

(5)(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(4) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative for a general account shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative or the finality of any decision or order by the Administrator under the NO_X Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative for a general account, including private legal disputes concerning the proceeds of NO_X allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.52 NO_X Allowance Tracking System responsibilities of NO_X authorized account representative.

(a) Following the establishment of a NO_X Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of NO_X allowances in the account, shall be made only by the NO_X authorized account representative for the account.

(b) *Authorized account representative identification.* The Administrator will assign a unique identifying number to each NO_X authorized account representative.

§ 96.53 Recordation of NO_X allowance allocations.

(a) The Administrator will record the NO_X allowances for 2003 in the NO_X Budget units' compliance accounts and the allocation set-asides, as allocated under subpart E of this part. The Administrator will also record the NO_X allowances allocated under § 96.88(a)(1) for each NO_X Budget opt-in source in its compliance account.

(b) Each year, after the Administrator has made all deductions from a NO_X Budget unit's compliance account and the overdraft account pursuant to § 96.54, the Administrator will record

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NO_X allowances, as allocated to the unit under subpart E of this part or under § 96.88(a)(2), in the compliance account for the year after the last year for which allowances were previously allocated to the compliance account. Each year, the Administrator will also record NO_X allowances, as allocated under subpart E of this part, in the allocation set-aside for the year after the last year for which allowances were previously allocated to an allocation set-aside.

(c) *Serial numbers for allocated NO_X allowances*. When allocating NO_X allowances to and recording them in an account, the Administrator will assign each NO_X allowance a unique identification number that will include digits identifying the year for which the NO_X allowance is allocated.

§ 96.54 Compliance.

(a) *NO_X allowance transfer deadline.* The NO_X allowances are available to be deducted for compliance with a unit's NO_X Budget emissions limitation for a control period in a given year only if the NO_X allowances:

(1) Were allocated for a control period in a prior year or the same year; and

(2) Are held in the unit's compliance account, or the overdraft account of the source where the unit is located, as of the NO_X allowance transfer deadline for that control period or are transferred into the compliance account or overdraft account by a NO_X allowance transfer correctly submitted for recordation under § 96.60 by the NO_X allowance transfer deadline for that control period.

(b) *Deductions for compliance.* (1) Following the recordation, in accordance with § 96.61, of NO_X allowance transfers submitted for recordation in the unit's compliance account or the overdraft account of the source where the unit is located by the NO_X allowance transfer deadline for a control period, the Administrator will deduct NO_X allowances available under paragraph (a) of this section to cover the unit's NO_X emissions (as determined in accordance with subpart H of this part), or to account for actual utilization under § 96.42(e), for the control period:

(i) From the compliance account; and

(ii) Only if no more NO_X allowances available under paragraph (a) of this section remain in the compliance account, from the overdraft account. In deducting allowances for units at the source from the overdraft account, the Administrator will begin with the unit having the compliance account with the lowest NO_X Allowance Tracking System account number and end with the unit having the compliance account with the highest NO_X Allowance Tracking System account number (with account numbers sorted beginning with the left-most character and ending with the right-most character and the letter characters assigned values in alphabetical order and less than all numeric characters).

(2) The Administrator will deduct NO_X allowances first under paragraph (b)(1)(i) of this section and then under paragraph (b)(1)(ii) of this section:

(i) Until the number of NO_X allowances deducted for the control period equals the number of tons of NO_X emissions, determined in accordance with subpart H of this part, from the unit for the control period for which compliance is being determined, plus the number of NO_X allowances required for deduction to account for actual utilization under § 96.42(e) for the control period; or

(ii) Until no more NO_X allowances available under paragraph (a) of this section remain in the respective account.

(c)(1) *Identification of NO_X allowances by serial number.* The NO_X authorized account representative for each compliance account may identify by serial number the NO_X allowances to be deducted from the unit's compliance account under paragraph (b), (d), or (e) of this section. Such identification shall be made in the compliance certification report submitted in accordance with § 96.30.

(2) *First-in, first-out.* The Administrator will deduct NO_X allowances for a control period from the compliance account, in the absence of an identification or in the case of a partial identification of NO_X allowances by serial number under paragraph (c)(1) of this section, or the overdraft account on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Those NO_X allowances that were allocated for the control period to the unit under subpart E or I of this part;

(ii) Those NO_X allowances that were allocated for the control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation;

(iii) Those NO_X allowances that were allocated for a prior control period to the unit under subpart E or I of this part; and

(iv) Those NO_X allowances that were allocated for a prior control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section, the Administrator will deduct from the unit's compliance account or the overdraft account of the source where the unit is located a number of NO_X allowances, allocated for a control period after the control period in which the unit has excess emissions, equal to three times the number of the unit's excess emissions.

(2) If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(3) Any allowance deduction required under paragraph (d) of this section shall not affect the liability of the owners and operators of the NO_X Budget unit for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the CAA or applicable State law. The following guidelines will be followed in assessing fines, penalties or other obligations:

(i) For purposes of determining the number of days of violation, if a NO_X Budget unit has excess emissions for a control period, each day in the control period (153 days) constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(ii) Each ton of excess emissions is a separate violation.

(e) Deductions for units sharing a common stack. In the case of units sharing a common stack and having emissions that are not separately monitored or apportioned in accordance with subpart H of this part:

(1) The NO_X authorized account representative of the units may identify the percentage of NO_X allowances to be deducted from each such unit's compliance account to cover the unit's share of NO_X emissions from the common stack for a control period. Such identification shall be made in the compliance certification report submitted in accordance with § 96.30.

(2) Notwithstanding paragraph (b)(2)(i) of this section, the Administrator will deduct NO_X allowances for each such unit until the number of NO_X allowances deducted equals the unit's identified percentage (under paragraph (e)(1) of this section) of the number of tons of NO_X emissions, as determined in accordance with subpart H of this part, from the common stack for the control period for which compliance is being determined or, if no percentage is identified, an equal

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percentage for each such unit, plus the number of allowances required for deduction to account for actual utilization under § 96.42(e) for the control period.

(f) The Administrator will record in the appropriate compliance account or overdraft account all deductions from such an account pursuant to paragraphs (b), (d), or (e) of this section.

§ 96.55 Banking.

(a) NO_X allowances may be banked for future use or transfer in a compliance account, an overdraft account, or a general account, as follows:

(1) Any NO_X allowance that is held in a compliance account, an overdraft account, or a general account will remain in such account unless and until the NO_X allowance is deducted or transferred under § 96.31, § 96.54, § 96.56, subpart G of this part, or subpart I of this part.

(2) The Administrator will designate, as a ''banked'' NO_X allowance, any NO_X allowance that remains in a compliance account, an overdraft account, or a general account after the Administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to § 96.54.

(b) Each year starting in 2004, after the Administrator has completed the designation of banked NO_X allowances under paragraph (a)(2) of this section and before May 1 of the year, the Administrator will determine the extent to which banked NO_X allowances may be used for compliance in the control period for the current year, as follows:

(1) The Administrator will determine the total number of banked NO_X allowances held in compliance accounts, overdraft accounts, or general accounts.

(2) If the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts is less than or equal to 10 % of the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located, any banked NO_X allowance may be deducted for compliance in accordance with § 96.54.

(3) If the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts exceeds 10 % of the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located, any banked allowance may be deducted for compliance in accordance with § 96.54, except as follows:

(i) The Administrator will determine the following ratio: 0.10 multiplied by the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located and divided by the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts.

(ii) The Administrator will multiply the number of banked NO_X allowances in each compliance account or overdraft account. The resulting product is the number of banked NO_X allowances in the account that may be deducted for compliance in accordance with § 96.54. Any banked NO_X allowances in excess of the resulting product may be deducted for compliance in accordance with § 96.54, except that, if such NO_X allowances are used to make a deduction, two such NO_X allowances must be deducted for each deduction of one NO_X allowance required under § 96.54.

(c) Any NO_X Budget unit may reduce its NO_X emission rate in the 2001 or 2002 control period, the owner or operator of the unit may request early reduction credits, and the permitting authority may allocate NO_X allowances in 2003 to the unit in accordance with the following requirements.

(1) Each NO_X Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall monitor NO_X emissions in accordance with subpart H of this part starting in the 2000 control period and for each control period for which such early reduction credits are requested. The unit's monitoring system availability shall be not less than 90 percent during the 2000 control period, and the unit must be in compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) NO_X emission rate and heat input under paragraphs (c)(3) through (5) of this section shall be determined in accordance with subpart H of this part.

(3) Each NO_X Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall reduce its NO_X emission rate, for each control period for which early reduction credits are requested, to less than both 0.25 lb/mmBtu and 80 percent of the unit's NO_X emission rate in the 2000 control period.

(4) The NO_X authorized account representative of a NO_X Budget unit that meets the requirements of paragraphs (c)(1)and (3) of this section may submit to the permitting authority a request for early reduction credits for the unit based on NO_X emission rate reductions made by the unit in the control period for 2001 or 2002 in accordance with paragraph (c)(3) of this section.

(i) In the early reduction credit request, the NO_X authorized account may request early reduction credits for such control period in an amount equal to the unit's heat input for such control period multiplied by the difference between 0.25 lb/mmBtu and the unit's NO_X emission rate for such control period, divided by 2000 lb/ton, and rounded to the nearest ton.

(ii) The early reduction credit request must be submitted, in a format specified by the permitting authority, by October 31 of the year in which the NO_X emission rate reductions on which the request is based are made or such later date approved by the permitting authority.

(5) The permitting authority will allocate NO_X allowances, to NO_X Budget units meeting the requirements of paragraphs (c)(1) and (3) of this section and covered by early reduction requests meeting the requirements of paragraph (c)(4)(ii) of this section, in accordance with the following procedures:

(i) Upon receipt of each early reduction credit request, the permitting authority will accept the request only if the requirements of paragraphs (c)(1), (c)(3), and (c)(4)(ii) of this section are met and, if the request is accepted, will make any necessary adjustments to the request to ensure that the amount of the early reduction credits requested meets the requirement of paragraphs (c)(2) and (4) of this section.

(ii) If the State's compliance supplement pool has an amount of NO_X allowances not less than the number of early reduction credits in all accepted early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate to each NO_X Budget unit covered by such accepted requests one allowance for each early reduction credit requested (as adjusted under paragraph (c)(5)(i) of this section).

(iii) If the State's compliance supplement pool has a smaller amount of NO_X allowances than the number of early reduction credits in all accepted early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate NO_X allowances to each NO_X Budget unit covered by such accepted requests according to the following formula:

Unit's allocated early reduction credits = [(Unit's adjusted early reduction credits) / (Total adjusted early reduction credits requested by all units)] x (Available NO_X allowances from the State's compliance supplement pool)

where:

''Unit's adjusted early reduction credits'' is the number of early reduction credits for the unit for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

''Total adjusted early reduction credits requested by all units'' is the number of early reduction credits for all units for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

''Available NO_X allowances from the State's compliance supplement pool'' is the number of NO_X allowances in the State's compliance supplement pool and available for early reduction credits for 2001 and 2002.

(6) By May 1, 2003, the permitting authority will submit to the Administrator the allocations of NO_X allowances determined under paragraph (c)(5) of this section. The Administrator will record such allocations to the extent that they are consistent with the requirements of paragraphs (c)(1) through (5) of this section.

(7) NO_X allowances recorded under paragraph (c)(6) of this section may be deducted for compliance under § 96.54 for the control periods in 2003 or 2004. Notwithstanding paragraph (a) of this section, the Administrator will deduct as retired any NO_X allowance that is recorded under paragraph (c)(6) of this section and is not deducted for compliance in accordance with § 96.54 for the control period in 2003 or 2004.

(8) NO_X allowances recorded under paragraph (c)(6) of this section are treated as banked allowances in 2004 for the purposes of paragraphs (a) and (b) of this section.

§ 96.56 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any NO_X Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the NO_X authorized account representative for the account.

§ 96.57 Closing of general accounts.

(a) The NO_X authorized account representative of a general account may instruct the Administrator to close the account by submitting a statement requesting deletion of the account from the NO_X Allowance Tracking System and by correctly submitting for recordation under § 96.60 an allowance transfer of all NO_X allowances in the account to one or more other NO_X Allowance Tracking System accounts.

(b) If a general account shows no activity for a period of a year or more and does not contain any NO_X allowances, the Administrator may notify the NO_X authorized account representative for the account that the account will be closed and deleted from the NO_X Allowance Tracking System following 20 business days after the notice is sent. The account will be closed after the 20-day period unless before the end of the 20-day period the Administrator receives a correctly submitted transfer of NO_X allowances into the account under § 96.60 or a statement submitted by the NO_X authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart G—NO_X Allowance Transfers

§ 96.60 Submission of NO_X allowance transfers.

The NO_X authorized account representatives seeking recordation of a NO_X allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the NO_X allowance transfer shall include the following elements in a format specified by the Administrator:

(a) The numbers identifying both the transferor and transferee accounts;

(b) A specification by serial number of each NO_X allowance to be transferred; and

(c) The printed name and signature of the NO_X authorized account representative of the transferor account and the date signed.

§ 96.61 EPA recordation.

(a) Within 5 business days of receiving a NO_X allowance transfer, except as provided in paragraph (b) of this section, the Administrator will record a NO_X allowance transfer by moving each NO_X allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.60;

(2) The transferor account includes each NO_X allowance identified by serial number in the transfer; and

(3) The transfer meets all other requirements of this part.

(b) A NO_X allowance transfer that is submitted for recordation following the NO_X allowance transfer deadline and that includes any NO_X allowances allocated for a control period prior to or the same as the control period to which the NO_X allowance transfer deadline applies will not be recorded until after completion of the process of recordation of NO_X allowance allocations in § 96.53(b).

(c) Where a NO_X allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.62 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a NO_X allowance transfer under § 96.61, the Administrator will notify each party to the transfer. Notice will be given to the NO_X authorized account representatives of both the transferror and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a NO_X allowance transfer that fails to meet the requirements of § 96.61(a), the Administrator will notify the NO_X authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and (2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a NO_X allowance transfer for recordation following notification of non-recordation.

Subpart H—Monitoring and Reporting

§ 96.70 General requirements.

The owners and operators, and to the extent applicable, the NO_X authorized account representative of a NO_X Budget unit, shall comply with the monitoring and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.2 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be replaced by the terms ''NO_X Budget unit,'' ''NO_X authorized account representative,'' and ''continuous emission monitoring system'' (or ''CEMS''), respectively, as defined in § 96.2.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each NO_X Budget unit must meet the following requirements. These provisions also apply to a unit for which an application for a NO_X Budget opt-in permit is submitted and not denied or withdrawn, as provided in subpart I of this part:

(1) Install all monitoring systems required under this subpart for

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monitoring NO_X mass. This includes all systems required to monitor NO_X emission rate, NO_X concentration, heat input, and flow, in accordance with §§ 75.72 and 75.76.

(2) Install all monitoring systems for monitoring heat input, if required under § 96.76 for developing NO_X allowance allocations.

(3) Successfully complete all certification tests required under § 96.71 and meet all other provisions of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

(4) Record, and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) *Compliance dates.* The owner or operator must meet the requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates and must record and report data on and after the following dates:

(1) NO_X Budget units for which the owner or operator intends to apply for early reduction credits under § 96.55(d) must comply with the requirements of this subpart by May 1, 2000.

(2) Except for NO_X Budget units under paragraph (b)(1) of this section, NO_X Budget units under § 96.4 that commence operation before January 1, 2002, must comply with the requirements of this subpart by May 1, 2002.

(3) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on an annual basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) May 1, 2002; or

(ii) The earlier of:

(A) 180 days after the date on which the unit commences operation or, (B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(4) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on a control season basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) The earlier of:

(A) 180 days after the date on which the unit commences operation or,

(B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(ii) However, if the applicable deadline under paragraph (b)(4)(i) section does not occur during a control period, May 1; immediately following the date determined in accordance with paragraph (b)(4)(i) of this section.

(5) For a NO_X Budget unit with a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2) or (b)(3) of this section or subpart I of this part:

(i) 90 days after the date on which emissions first exit to the atmosphere through the new stack or flue;

(ii) However, if the unit reports on a control season basis under § 96.74(d) and the applicable deadline under paragraph (b)(5)(i) of this section does not occur during the control period, May 1 immediately following the applicable deadline in paragraph (b)(5)(i) of this section.

(6) For a unit for which an application for a NO_X Budget opt in permit is submitted and not denied or withdrawn, the compliance dates specified under subpart I of this part.

(c) Reporting data prior to initial certification. (1) The owner or operator of a NO_X Budget unit that misses the certification deadline under paragraph (b)(1) of this section is not eligible to apply for early reduction credits. The owner or operator of the unit becomes subject to the certification deadline under paragraph (b)(2) of this section.

(2) The owner or operator of a NO_X Budget under paragraphs (b)(3) or (b)(4) of this section must determine, record and report NO_X mass, heat input (if required for purposes of allocations) and any other values required to determine NO_X Mass (e.g. NO_X emission rate and heat input or NO_X concentration and stack flow) using the provisions of § 75.70(g) of this chapter, from the date and hour that the unit starts operating until all required certification tests are successfully completed.

(d) *Prohibitions.* (1) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with § 96.75.

(2) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(3) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(4) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The NO_X authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 96.71(b)(2).

§ 96.71 Initial certification and recertification procedures

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.17 of this chapter, the NO_X authorized account representative shall resubmit the petition to the Administrator under § 96.75(a) to determine if the approval applies under the NO_X Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in § 75.72 of this chapter, or for any NO_X concentration CEMS used under the provisions of § 75.71(a)(2) of this chapter, the owner or operator shall

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meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures, except that the owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 shall also meet the requirements of paragraph (c) of this section and the owner or operator of a unit that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall also meet the requirements of paragraph (d) of this section. The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation, but requires additional CEMS under the common stack provisions in § 75.72 of this chapter, or that uses a NO_X concentration CEMS under § 75.71(a)(2) of this chapter also shall comply with the following initial certification and recertification procedures.

(1) Requirements for initial certification. The owner or operator shall ensure that each monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter. The owner or operator shall ensure that all applicable certification tests are successfully completed by the deadlines specified in § 96.70(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this part in a location where no such monitoring system was previously installed, initial certification according to § 75.20 is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the permitting authority determines significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system according to § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the permitting authority determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to § 75.20(b) of this chapter. Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) Certification approval process for initial certifications and recertification. (i) *Notification of certification.* The NO_X authorized account representative shall submit to the permitting authority, the appropriate EPA Regional Office and the permitting authority a written notice of the dates of certification in accordance with § 96.73.

(ii) *Certification application.* The NO_X authorized account representative shall submit to the permitting authority a certification application for each monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter.

(iii) Except for units using the low mass emission excepted methodology under § 75.19 of this chapter, the provisional certification date for a monitor shall be determined using the procedures set forth in § 75.20(a)(3) of this chapter. A provisionally certified monitor may be used under the NO_X Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system or component thereof under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority.

(iv) Certification application formal approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NO_X Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the permitting authority. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the NO_X authorized account representative must submit the additional information required to complete the certification application. If the NO_X authorized account representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality-assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in paragraph (b)(3)(v) of this section for each monitoring system or component thereof which is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.72(b).

(v) Procedures for loss of certification. If the permitting authority issues a notice of disapproval of a certification application under paragraph

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(b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under § 75.20(a)(5)(i) of this chapter:

(1) For units using or intending to monitor for NO_X emission rate and heat input or for units using the low mass emission excepted methodology under § 75.19 of this chapter, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit.

(2) For units intending to monitor for NO_X mass emissions using a NO_X pollutant concentration monitor and a flow monitor, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of appendix A of part 75 of this chapter;

(B) The NO_X authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section; and

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 of this chapter shall meet the applicable general operating requirements of § 75.10 of this chapter, the applicable requirements of § 75.19 of this chapter, and the applicable certification requirements of § 96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program, as of the following dates:

(1) For units that are reporting on an annual basis under § 96.74(d);

(i) For a unit that has commences operation before its compliance deadline under § 96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commences operation after its compliance deadline under § 96.71(b), the date of submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for permitting authority review, or

(2) For units that are reporting on a control period basis under § 96.74(b)(3)(ii) of this part:

(i) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted before May 1, from May 1 of the year of the submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(iii) For a unit that commences operation after its compliance deadline under § 96.71(b), where the unit commences operation before May 1, from May 1 of the year that the unit commenced operation, until the completion of the period for the permitting authority's review.

(iv) For a unit that has not operated after its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, but before October 1st, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority's review.

(d) Certification/recertification procedures for alternative monitoring systems. The NO_X authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NO_X Trading Program. The NO_X authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and § 75.20(f) of this chapter .

§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, data shall be substituted using the applicable procedures in subpart D, appendix D, or appendix E of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.71 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the system or component. The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the initial certification or recertification procedures in § 96.71 for each disapproved system.

§ 96.73 Notifications.

The NO_X authorized account representative for a NO_X Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

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§ 96.74 Recordkeeping and reporting.

(a) *General provisions.* (1) The NO_X authorized account representative shall comply with all recordkeeping and reporting requirements in this section and with the requirements of § 96.10(e).

(2) If the NO_X authorized account representative for a NO_X Budget unit subject to an Acid Rain Emission limitation who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and which includes data and information required under this subpart or subpart H of part 75 of this chapter is not the same person as the designated representative or the alternative designated representative for the unit under part 72 of this chapter, the submission must also be signed by the designated representative or the alternative designated representative.

(b) *Monitoring plans.* (1) The owner or operator of a unit subject to an Acid Rain emissions limitation shall comply with requirements of § 75.62 of this chapter, except that the monitoring plan shall also include all of the information required by subpart H of part 75 of this chapter.

(2) The owner or operator of a unit that is not subject to an Acid Rain emissions limitation shall comply with requirements of § 75.62 of this chapter, except that the monitoring plan is only required to include the information required by subpart H of part 75 of this chapter.

(c) *Certification applications.* The NO_X authorized account representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.71 including the information required under subpart H of part 75 of this chapter.

(d) *Quarterly reports.* The NO_X authorized account representative shall submit quarterly reports, as follows:

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NO_X budget unit chooses to meet the annual reporting requirements of this subpart H, the NO_X authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

(i) For units that elect to comply with the early reduction credit provisions under § 96.55 of this part, the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii). Data shall be reported from the date and hour corresponding to the date and hour of provisional certification; or

(ii) For units commencing operation prior to May 1, 2002 that are not required to certify monitors by May 1, 2000 under § 96.70(b)(1), the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1, 2002, the partial calender quarter from May 1, 2002 through June 30, 2002. Data shall be recorded and reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour on May 1, 2002; or

(iii) For a unit that commences operation after May 1, 2002, the calendar quarter in which the unit commences operation, Data shall be reported from the date and hour corresponding to when the unit commenced operation.

(2) If a NO_X budget unit is not subject to an Acid Rain emission limitation, then the NO_X authorized account representative shall either:

(i) Meet all of the requirements of part 75 related to monitoring and reporting NO_X mass emissions during the entire year and meet the reporting deadlines specified in paragraph (d)(1) of this section; or

(ii) Submit quarterly reports only for the periods from the earlier of May 1 or the date and hour that the owner or operator successfully completes all of the recertification tests required under § 75.74(d)(3) through September 30 of each year in accordance with the provisions of § 75.74(b) of this chapter. The NO_X authorized account representative shall submit a quarterly report for each calendar quarter, beginning with:

(A) For units that elect to comply with the early reduction credit provisions under § 96.55, the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii). Data shall be reported from the date and hour corresponding to the date and hour of provisional certification; or

(B) For units commencing operation prior to May 1, 2002 that are not required to certify monitors by May 1, 2000 under § 96.70(b)(1), the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii), or if the certification tests are not completed by May 1, 2002, the partial calender quarter from May 1, 2002 through June 30, 2002. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1, 2002; or

(C) For units that commence operation after May 1, 2002 during the control period, the calender quarter in which the unit commences operation. Data shall be reported from the date and hour corresponding to when the unit commenced operation; or

(D) For units that commence operation after May 1, 2002 and before May 1 of the year in which the unit commences operation, the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1 of the year in which the unit commences operation, May 1 of the year in which the unit commences operation. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1 of the year after the unit commences operation.

(E) For units that commence operation after May 1, 2002 and after September 30 of the year in which the unit commences operation, the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1 of the year after the unit commences operation, May 1 of the year after the unit commences operation. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1 of the year after the unit commences operation.

(3) The NO_X authorized account representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in subpart H of part 75 of this chapter and § 75.64 of this chapter.

(i) For units subject to an Acid Rain Emissions limitation, quarterly reports shall include all of the data and information required in subpart H of part 75 of this chapter for each NO_X Budget unit (or group of units using a common stack) as well as information required in subpart G of part 75 of this chapter.

(ii) For units not subject to an Acid Rain Emissions limitation, quarterly reports are only required to include all of the data and information required in subpart H of part 75 of this chapter for each NO_X Budget unit (or group of units using a common stack).

(4) *Compliance certification.* The NO_X authorized account representative shall submit to the Administrator a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly

and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(ii) For a unit with add-on NO_X emission controls and for all hours where data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_X emissions; and

(iii) For a unit that is reporting on a control period basis under § 96.74(d) the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 96.75 Petitions.

(a) The NO_X authorized account representative of a NO_X Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (a)(1) of this section, if the petition requests approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of § 75.72 of this chapter, the petition is governed by paragraph (b) of this section.

(b) The NO_X authorized account representative of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) The NO_X authorized account representative of a NO_X Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of § 75.72 of this chapter or a NO_X concentration CEMS used under 75.71(a)(2) of this chapter.

(2) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent the petition under paragraph (b) of this section is approved by both the permitting authority and the Administrator.

§ 96.76 Additional requirements to provide heat input data for allocations purposes.

(a) The owner or operator of a unit that elects to monitor and report NO_X Mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in part 75 of this chapter for any source located in a state developing source allocations based upon heat input.

(b) The owner or operator of a unit that monitor and report NO_X Mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in part 75 of this chapter for any source that is applying for early reduction credits under § 96.55.

Subpart I—Individual Unit Opt-ins

§ 96.80 Applicability.

A unit that is in the State, is not a NO_X Budget unit under § 96.4, vents all of its emissions to a stack, and is operating, may qualify, under this subpart, to become a NO_X Budget opt- in source. A unit that is a NO_X Budget unit, is covered by a retired unit exemption under § 96.5 that is in effect, or is not operating is not eligible to become a NO_X Budget opt-in source.

§ 96.81 General.

Except otherwise as provided in this part, a NO_X Budget opt-in source shall be treated as a NO_X Budget unit for purposes of applying subparts A through H of this part.

§ 96.82 NO_X authorized account representative.

A unit for which an application for a NO_X Budget opt-in permit is submitted and not denied or withdrawn, or a NO_X Budget opt-in source, located at the same source as one or more NO_X Budget units, shall have the same NO_X authorized account representative as such NO_X Budget units.

§ 96.83 Applying for NO_X Budget opt-in permit.

(a) *Applying for initial NO_X Budget opt-in permit.* In order to apply for an initial NO_X Budget opt-in permit, the NO_X authorized account representative of a unit qualified under § 96.80 may submit to the permitting authority at any time, except as provided under § 96.86(g):

(1) A complete NO_X Budget permit application under § 96.22;

(2) A monitoring plan submitted in accordance with subpart H of this part; and

(3) A complete account certificate of representation under § 96.13, if no NO_X authorized account representative has been previously designated for the unit.

(b) *Duty to reapply.* The NO_X authorized account representative of a NO_X Budget opt-in source shall submit a complete NO_X Budget permit application under § 96.22 to renew the NO_X Budget opt-in permit in accordance with § 96.21(c) and, if applicable, an updated monitoring plan in accordance with subpart H of this part.

§ 96.84 Opt-in process.

The permitting authority will issue or deny a NO_X Budget opt-in permit for a unit for which an initial application for a NO_X Budget opt-in permit under § 96.83 is submitted, in accordance with § 96.20 and the following:

(a) *Interim review of monitoring plan.* The permitting authority will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a NO_X Budget opt-in permit under § 96.83. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit are monitored and reported in accordance with subpart H of this part. A determination of sufficiency shall not be construed as acceptance or approval of the unit's monitoring plan.

(b) If the permitting authority determines that the unit's monitoring plan is sufficient under paragraph (a) of this section and after completion of monitoring system certification under subpart H of this part, the NO_X emissions rate and the heat input of the unit shall be monitored and reported in accordance with subpart H of this part for one full control period during which monitoring system availability is not less than 90 percent and during which the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements. Solely for purposes of applying the requirements in the prior sentence, the unit shall be treated as a ''NO_X Budget unit'' prior to issuance of a NO_X Budget opt-in permit covering the unit.

(c) Based on the information monitored and reported under paragraph (b) of this section, the unit's baseline heat rate shall be calculated as the unit's total heat input (in mmBtu) for the control period and the unit's baseline NO_X emissions rate shall be calculated as the unit's total NO_X emissions (in lb) for the control period divided by the unit's baseline heat rate.

(d) After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraph (c) of this section, the permitting authority will serve a draft NO_X Budget opt-in permit on the NO_X authorized account representative of the unit.

(e) *Confirmation of intention to opt-in.* Within 20 days after the issuance of the draft NO_X Budget opt-in permit, the NO_X authorized account representative of the unit must submit to the permitting authority a confirmation of the intention to opt in the unit or a withdrawal of the application for a NO_X Budget opt-in permit under § 96.83. The permitting authority will treat the failure to make a timely submission as a withdrawal of the NO_X Budget opt-in permit application.

(f) *Issuance of draft NO_X Budget opt-in permit.* If the NO_X authorized account representative confirms the intention to opt-in the unit under paragraph (e) of this section, the permitting authority will issue the draft NO_X Budget opt-in permit in accordance with § 96.20.

(g) Notwithstanding paragraphs (a) through (f) of this section, if at any time before issuance of a draft NO_X Budget opt-in permit for the unit, the permitting authority determines that the unit does not qualify as a NO_X Budget opt-in source under § 96.80, the permitting authority will issue a draft denial of a NO_X Budget opt-in permit for the unit in accordance with § 96.20.

(h) *Withdrawal of application for NO_X Budget opt-in permit.* A NO_X authorized account representative of a unit may withdraw its application for a NO_X Budget opt-in permit under § 96.83 at any time prior to the issuance of the final NO_X Budget opt-in permit. Once the application for a NO_X Budget opt-in permit is withdrawn, a NO_X authorized account representative wanting to reapply must submit a new application for a NO_X Budget permit under § 96.83.

(i) *Effective date.* The effective date of the initial NO_X Budget opt-in permit shall be May 1 of the first control period starting after the issuance of the initial NO_X Budget opt-in permit by the permitting authority. The unit shall be a NO_X Budget opt-in source and a NO_X Budget unit as of the effective date of the initial NO_X Budget opt-in permit.

§ 96.85 NO_X Budget opt-in permit contents.

(a) Each NO_X Budget opt-in permit (including any draft or proposed NO_X Budget opt-in permit, if applicable) will contain all elements required for a complete NO_X Budget opt-in permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of NO_X allowances to or from the compliance accounts of each NO_X Budget opt-in source covered by the NO_X Budget opt-in permit or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located.

§ 96.86 Withdrawal from NO_X Budget Trading Program.

(a) *Requesting withdrawal.* To withdraw from the NO_X Budget Trading Program, the NO_X authorized account representative of a NO_X Budget opt-in source shall submit to the permitting authority a request to withdraw effective as of a specified date prior to May 1 or after September 30. The submission shall be made no later than 90 days prior to the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a NO_X Budget opt-in source covered by a request under paragraph (a) of this section may withdraw from the NO_X Budget Trading Program and the NO_X Budget opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period immediately before the withdrawal is to be effective, the NO_X authorized account representative must submit or must have submitted to the permitting authority an annual compliance certification report in accordance with § 96.30.

(2) If the NO_X Budget opt-in source has excess emissions for the control period immediately before the withdrawal is to be effective, the Administrator will deduct or has deducted from the NO_X Budget opt-in source's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, the full amount required under § 96.54(d) for the control period.

(3) After the requirements for withdrawal under paragraphs (b)(1) and (2) of this section are met, the Administrator will deduct from the NO_X Budget opt-in source's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, NO_X allowances equal in number to and allocated for the same or a prior control period as any NO_X allowances allocated to that source under § 96.88 for any control period for which the withdrawal is to be effective. The Administrator will close the NO_X Budget opt-in source's compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NO_X Budget opt-in source. The NO_X authorized account representative for the NO_X Budget opt- in source shall become the NO_X authorized account representative for the general account.

(c) A NO_X Budget opt-in source that withdraws from the NO_X Budget Trading Program shall comply with all requirements under the NO_X Budget Trading Program concerning all years for which such NO_X Budget opt-in source was a NO_X Budget opt-in source, even if such requirements arise or must be complied with after the withdrawal takes effect.

(d) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of NO_X allowances required), the permitting authority will issue a notification to the NO_X authorized account representative of the NO_X Budget opt-in source of the acceptance of the withdrawal of the NO_X Budget opt-in source as of a specified effective date that is after such requirements have been met and that is prior to May 1 or after September 30.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the NO_X authorized account representative of the NO_X Budget opt-in source that the NO_X Budget opt-in source's request to withdraw is denied. If the NO_X Budget opt-in source's request to withdraw is denied, the NO_X Budget opt-in source shall remain subject to the requirements for a NO_X Budget opt-in source.

(e) *Permit amendment.* After the permitting authority issues a notification under paragraph (d)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the NO_X Budget permit covering the NO_X Budget opt-in source to terminate the NO_X Budget opt-in permit as of the effective date specified under paragraph (d)(1) of this section. A NO_X Budget opt-in source shall continue to be a NO_X Budget opt-in source until the effective date of the termination.

(f) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the NO_X Budget opt-in source's request to withdraw, the NO_X authorized account representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(g) *Ability to return to the NO_X Budget Trading Program.* Once a NO_X Budget opt-in source withdraws from the NO_X Budget Trading Program and its NO_X Budget opt-in permit is terminated under this section, the NO_X authority account representative may not submit another application for a NO_X Budget opt-in permit under § 96.83 for the unit prior to the date that is 4 years after the date on which the terminated NO_X Budget opt-in permit became effective.

§ 96.87 Change in regulatory status.

(a) *Notification.* When a NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4, the NO_X authorized account representative shall notify in writing the permitting authority and the Administrator of such change in the NO_X Budget opt-in source's regulatory status, within 30 days of such change.

(b) Permitting authority's and Administrator's action. (1)(i) When the NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4, the permitting authority will revise the NO_X Budget opt-in source's NO_X Budget opt-in permit to meet the requirements of a NO_X Budget permit under § 96.23 as of an effective date that is the date on which such NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4.

(ii)(A) The Administrator will deduct from the compliance account for the NO_X Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO_X Budget source where the unit is located, NO_X allowances equal in number to and allocated for the same or a prior control period as:

(1) Any NO_X allowances allocated to the NO_X Budget unit (as a NO_X Budget opt-in source) under § 96.88 for any control period after the last control period during which the unit's NO_X Budget opt-in permit was effective; and

(2) If the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the NO_X allowances allocated to the NO_X Budget unit (as a NO_X Budget opt-in source) under § 96.88 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(B) The NO_X authorized account representative shall ensure that the compliance account of the NO_X Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO_X Budget source where the unit is located, includes the NO_X allowances necessary for completion of the deduction under paragraph (b)(1)(ii)(A) of this section. If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(iii)(A) For every control period during which the NO_X Budget permit revised under paragraph (b)(1)(i) of this section is effective, the NO_X Budget unit under paragraph (b)(1)(i) of this section will be treated, solely for purposes of NO_X allowance allocations under § 96.42, as a unit that commenced operation on the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section and will be allocated NO_X allowances under § 96.42.

(B) Notwithstanding paragraph (b)(1)(iii)(A) of this section, if the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the following number of NO_X allowances will be allocated to the NO_X Budget unit under paragraph (b)(1)(i) of this section under § 96.42 for the control period: the number of NO_X allowances otherwise allocated to the NO_X Budget unit under § 96.42 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(2)(i) When the NO_X authorized account representative of a NO_X Budget opt-in source does not renew its NO_X Budget opt-in permit under § 96.83(b), the Administrator will deduct from the NO_X Budget opt-in unit's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, NO_X allowances equal in number to and allocated for the same or a prior control period as any NO_X allowances allocated to the NO_X Budget opt-in source under § 96.88 for any control period after the last control period for which the NO_X Budget opt-in permit is effective. The NO_X authorized account representative shall ensure that the NO_X Budget opt-in source's compliance account or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located includes the NO_X allowances necessary for completion of such deduction. If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(ii) After the deduction under paragraph (b)(2)(i) of this section is completed, the Administrator will close the NO_X Budget opt-in source's compliance account. If any NO_X allowances remain in the compliance account after completion of such deduction and any deduction under § 96.54, the Administrator will close the NO_X Budget opt-in source's compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NO_X Budget opt-in source. The NO_X authorized account representative for the NO_X Budget opt- in source shall become the NO_X authorized account representative for the general account.

§ 96.88 NO_X allowance allocations to opt-in units.

(a) *NO_X allowance allocation.* (1) By December 31 immediately before the first control period for which the NO_X Budget opt-in permit is effective, the permitting authority will allocate NO_X allowances to the NO_X Budget opt-in source and submit to the Administrator the allocation for the control period in accordance with paragraph (b) of this section.

(2) By no later than December 31, after the first control period for which the NO_X Budget opt-in permit is in effect, and December 31 of each year thereafter, the permitting authority will allocate NO_X allowances to the NO_X Budget opt- in source, and submit to the Administrator allocations for the next control period, in accordance with paragraph (b) of this section.

(b) For each control period for which the NO_X Budget opt-in source has an approved NO_X Budget opt-in permit, the NO_X Budget opt-in source will be allocated NO_X allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating NO_X allowance allocations will be the lesser of:

(i) The NO_X Budget opt-in source's baseline heat input determined pursuant to § 96.84(c); or

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(ii) The NO_X Budget opt-in source's heat input, as determined in accordance with subpart H of this part, for the control period in the year prior to the year of the control period for which the NO_X allocations are being calculated.

(2) The permitting authority will allocate NO_X allowances to the NO_X Budget opt-in source in an amount equaling the heat input (in mmBtu) determined under paragraph (b)(1) of this section multiplied by the lesser of:

(i) The NO_X Budget opt-in source's baseline NO_X emissions rate (in lb/mmBtu) determined pursuant to § 96.84(c); or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the NO_X Budget opt-in source during the control period.

Subpart J—Mobile and Area Sources [Reserved]

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Part II

Environmental Protection Agency

40 CFR Parts 51, 72, et al.

Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call; Final Rule

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 73, 74, 77, 78 and 96

[OAR–2003–0053; FRL–7885–9]

RIN 2060–AL76

Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In today's action, EPA finds that 28 States and the District of Columbia contribute significantly to nonattainment of the national ambient air quality standards (NAAQS) for fine particles ($PM_{2.5}$) and/or 8-hour ozone in downwind States. The EPA is requiring these upwind States to revise their State implementation plans (SIPs) to include control measures to reduce emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X). Sulfur dioxide is a precursor to $PM_{2.5}$ formation, and NO_X is a precursor to both ozone and $PM_{2.5}$ formation. Reducing upwind precursor emissions will assist the downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas in achieving the NAAQS. Moreover, attainment will be achieved in a more equitable, cost-effective manner than if each nonattainment area attempted to achieve attainment by implementing local emissions reductions alone.

Based on State obligations to address interstate transport of pollutants under section 110(a)(2)(D) of the Clean Air Act (CAA), EPA is specifying statewide emissions reduction requirements for SO_2 and NO_X. The EPA is specifying that the emissions reductions be implemented in two phases. The first phase of NO_X reductions starts in 2009 (covering 2009–2014) and the first phase of SO_2 reductions starts in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 starts in 2015 (covering 2015 and thereafter). The required emissions reductions requirements are based on controls that are known to be highly cost effective for electric generating units (EGUs).

Today's action also includes model rules for multi-State cap and trade programs for annual SO_2 and NO_X emissions for $PM_{2.5}$ and seasonal NO_X emissions for ozone that States can choose to adopt to meet the required emissions reductions in a flexible and cost-effective manner.

Today's action also includes revisions to the Acid Rain Program regulations under title IV of the CAA, particularly the regulatory provisions governing the SO_2 cap and trade program. The revisions are made because they streamline the operation of the Acid Rain SO_2 cap and trade program and/or facilitate the interaction of that cap and trade program with the model SO_2 cap and trade program included in today's action. In addition, today's action provides for the NO_X SIP Call cap and trade program to be replaced by the CAIR ozone-season NO_X trading program.

DATES: The effective date of today's action, except for the revisions to 40 CFR parts 72, 73, 74, and 77 of the Acid Rain Program regulations, is July 11, 2005. States must submit to EPA for approval enforceable plans for complying with the requirements of this rule by September 11, 2006. The effective date for today's revisions to 40 CFR parts 72, 73, 74, and 77 of the Acid Rain Program regulations is July 1, 2006.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. OAR–2003–0053. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the EPA Docket Center, EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For general questions concerning today's action, please contact Carla Oldham, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, Mail Code C539–02, Research Triangle Park, NC, 27711, telephone (919) 541–3347, e-mail at *oldham.carla@epa.gov*. For legal questions, please contact Sonja Petersen, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 564–4079, e-mail at *petersen.sonja@epa.gov*. For questions regarding air quality analyses, please contact Norm Possiel, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D243–01, Research Triangle Park, NC, 27711, telephone (919) 541–5692, e-mail at *possiel.norm@epa.gov*. For questions regarding the EGU cost analyses, emissions inventories, and budgets, please contact Roman Kramarchuk, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9089, e-mail at *kramarchuk.roman@epa.gov*. For questions regarding statewide emissions inventories, please contact Ron Ryan, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D205–01, Research Triangle Park, NC, 27711, telephone (919) 541–4330, e-mail at *ryan.ron@epa.gov*. For questions regarding emissions reporting requirements, please contact Bill Kuykendal, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D205–01, Research Triangle Park, NC, 27711, telephone (919) 541–5372, e-mail at *kuykendal.bill@epa.gov*. For questions regarding the model cap and trade programs, please contact Sam Waltzer, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9175, e-mail at *waltzer.sam@epa.gov*. For questions regarding analyses required by statutes and executive orders, please contact Linda Chappell, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, Mail Code C339–01, Research Triangle Park, NC, 27711, telephone (919) 541–2864, e-mail at *chappell.linda@epa.gov*. For questions regarding the Acid Rain Program regulation revisions, please contact Dwight C. Alpern, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9151, e-mail at *alpern.dwight@epa.gov*.

SUPPLEMENTARY INFORMATION:

Regulated Entities

Except for the revisions to the Acid Rain Program regulations, this action does not directly regulate emissions sources. Instead, it requires States to

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revise their SIPs to include control measures to reduce emissions of NO_X and SO_2. The emissions reductions requirement assigned to the States are based on controls that are known to be highly cost effective for EGUs.

Entities potentially regulated by the revisions to the Acid Rain Program regulations in this action are fossil-fuel-fired boilers, turbines, and internal combustion engines, including those that serve generators producing electricity, generate steam, or cogenerate electricity and steam. Regulated categories and entities include:

Category	[1] NAICS code	Examples of potentially regulated entities
Industry	221112 and others	Electric service providers, boilers, turbines, and internal combustion engines from a wide range of industries.
Federal government	22112[2]	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government.	22112[2] 921150	Fossil fuel-fired electric utility steam generating units owned by municipalities. Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by the revisions to the Acid Rain Program regulations in this action. This table lists the types of entities that EPA is aware could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated, you should carefully examine the applicability criteria in 40 CFR 72.6 and 74.2 and the exemptions in 40 CFR 72.7 and 72.8. If you have questions regarding the applicability of the revisions to the Acid Rain Program regulations in this action to a particular entity, consult persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Web Site for Rulemaking Information

The EPA has also established a Web site for this rulemaking at *http://www.epa.gov/cleanairinterstaterule/* or *http://www.epa.gov/cair/* (formerly at *http://www.epa.gov/interstateairquality/*) which includes the rulemaking actions and certain other related information that the public may find useful.

Outline

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I. Overview

By notice of proposed rulemaking dated January 30, 2004 and by notice of supplemental rulemaking dated June 10, 2004, EPA proposed to find that certain States must reduce emissions of SO_2 and/or NO_X because those emissions contribute significantly to downwind areas in other States that are not meeting the annual $PM_{2.5}$ NAAQS or the 8-hour ozone NAAQS.[1] Today, EPA takes final action requiring 28 States and the District of Columbia to adopt and submit revisions to their State implementation plans (SIPs), under the requirements of CAA section 110(a)(2)(D), that would eliminate specified amounts of SO_2 and/or NO_X emissions.

Each State may independently determine which emissions sources to subject to controls, and which control measures to adopt. The EPA's analysis indicates that emissions reductions from electric generating units (EGUs) are highly cost effective, and EPA encourages States to adopt controls for EGUs. States that do so must place an enforceable limit, or cap, on EGU emissions (see section VII for discussion). The EPA has calculated the amount of each State's EGU emissions cap, or budget, based on reductions that EPA has determined are highly cost effective. States may allow their EGUs to participate in an EPA-administered cap and trade program as a way to reduce the cost of compliance, and to provide compliance flexibility. The cap and trade programs are described in more detail in section VIII.

The EPA estimates that today's action will reduce SO_2 emissions by 3.5 million tons [2] in 2010 and by 3.8 million tons in 2015; and would reduce annual NO_X emissions by 1.2 million tons in 2009 and by 1.5 million tons in 2015.[2] (These numbers are for the 23 States and the District of Columbia that are affected by the annual SO_2 and NO_X requirements of CAIR.) If all the affected States choose to achieve these reductions through EGU controls, then EGU SO_2 emissions in the affected States would be capped at 3.6 million tons in 2010 and 2.5 million tons in 2015[4]; and EGU annual NO_X emissions would be capped at 1.5 million tons in 2009 and 1.3 million tons in 2015. The EPA estimates that the required SO_2 and NO_X emissions reductions would, by themselves, bring into attainment 52 of the 79 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2010, and 57 of the 74 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2015. The EPA further estimates that the required NO_X emissions reductions would, by themselves, bring into attainment 3 of the 40 counties that are otherwise projected to be in nonattainment for 8-hour ozone in 2010, and 6 of the 22 counties that are projected to be in nonattainment for 8-hour ozone in 2015. In addition, today's rule will improve $PM_{2.5}$ and 8-hour ozone air quality in the areas that would remain

[1] ''Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule,'' (69 FR 4566, January 30, 2004) (NPR or January Proposal); ''Supplemental Proposal for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Proposed Rule,'' (69 FR 32684, June 10, 2004) (SNPR or Supplemental Proposal).

[2] These data are from EPA's most recent IPM modeling reflecting the final CAIR of today's notice. These results may differ slightly from those appearing in elsewhere in this preamble and the RIA, which were largely based upon a model run that included Arkansas, Delaware, and New Jersey in the annual CAIR requirements and also did not apply an ozone season cap on any States (the modeling was completed before EPA had determined the final scope of CAIR because of the length of time necessary to perform air quality modeling).

[3] These values represent reductions from future projected emissions without CAIR. In 2010 CAIR will reduce SO_2 by 4.3 million tons from 2003 levels and in 2015 it will reduce SO_2 emissions by 5.4 million tons from 2003 levels. In 2009, CAIR will reduce NO_X levels by 1.7 million tons from 2003 levels and in 2015 it will reduce NO_X levels by 2.0 million tons from 2003 levels.

[4] It should be noted that the banking provisions of the cap and trade program which encourage sources to make significant reductions before 2010 also allow sources to operate above these cap levels until all of the banked allowances are used, therefore EPA does not project that these caps will be met in 2010 or 2015.

nonattainment for those two NAAQS after implementation of today's rule. Because of today's rule, the States with those remaining nonattainment areas will find it less burdensome and less expensive to reach attainment by adopting additional local controls. The Clean Air Interstate Rule (CAIR) will also reduce $PM_{2.5}$ and 8-hour ozone levels in attainment areas, providing significant health and environmental benefits in all areas of the eastern US.

The EPA's CAIR and the previously promulgated NO_X SIP Call reflect EPA's determination that the required SO_2 and NO_X reductions are sufficient to eliminate upwind States' significant contribution to downwind nonattainment. These programs are not designed to eliminate all contributions to transport, but rather to balance the burden for achieving attainment between regional-scale and local-scale control programs.

The EPA conducted a regulatory impact analysis (RIA), entitled ''Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005)'' that estimates the annual private compliance costs (1999$) of $2.4 billion for 2010 and $3.6 billion for 2015, if all States make the required emissions reductions through the power industry. Additionally, the RIA includes a benefit-cost analysis demonstrating that substantial net economic benefits to society will be achieved from the emissions reductions required in this rulemaking. For determination of net benefits, the above private costs were converted to social costs that are lower since transfer payments, such as taxes, are removed from the estimates. The EPA analysis shows that today's action inclusive of the concurrent New Jersey and Delaware proposal will generate annual net benefits of approximately $71.4 or $60.4 billion in 2010 and $98.5 or $83.2 billion in 2015.[5] These alternate net benefit estimates reflect differing assumptions about the social discount rate used to estimate the benefits and costs of the rule. The lower estimates reflect a discount rate of 7 percent and the higher estimates a discount rate of 3 percent. In 2015, the total annual quantified benefits are $101 or $86.3 billion and the annual social costs are $2.6 or $3.1 billion—benefits outweigh costs in 2015 by a ratio of 39 to 1 or 28 to 1 (3 percent and 7 percent discount rates, respectively). These estimates do not include the value of benefits or costs that we cannot monetize.

In 2015, we estimate that PM-related annual benefits include approximately 17,000 fewer premature fatalities, 8,700 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 10,500 fewer hospitalization admissions (for respiratory and cardiovascular disease combined) and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of 9.9 million fewer minor restricted activity days) and approximately 1,700,000 fewer work loss days. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the Eastern U.S.). Based upon modeling for 2015, annual ozone-related health benefits are expected to include 2,800 fewer hospital admissions for respiratory illnesses, 280 fewer emergency room admissions for asthma, 690,000 fewer days with restricted activity levels, and 510,000 fewer days where children are absent from school due to illnesses.

In addition to these significant health benefits, the rule will result in ecological and welfare benefits. These benefits include visibility improvements; reductions in acidification in lakes, streams, and forests; reduced eutrophication in water bodies; and benefits from reduced ozone levels for forests and agricultural production.

Several other documents containing detailed explanations of other key elements of today's rule are also included in the docket. These include a detailed explanation of how EPA calculated the State-by-State EGU emissions budgets, and a detailed explanation of the air quality modeling analyses which support this rule.[6] Responses to comments that are not addressed in the preamble to today's rule are included in a separate document.[7]

The remaining sections of the preamble describe the final CAIR requirements and our responses to comments on many of the most important features of the CAIR. Section II, ''EPA's Analytical Approach,'' summarizes EPA's overall analytical approach and responds to general comments on that approach. Section III, ''Why Does This Rule Focus on SO_2 and NO_X, and How Were Significant Downwind Impacts Determined?,'' outlines the rationale for the CAIR focus on SO_2 and NO_X, which are precursors that contribute to $PM_{2.5}$ (SO_2, NO_X) or ozone (NO_X) transport, and the analytic approach EPA used to determine which States had large enough downwind ambient air quality impacts to become subject to today's requirements. Section IV, ''What Amounts of SO_2 and NO_X Emissions Did EPA Determine Should Be Reduced?,'' describes EPA's methodology for determining the amounts of SO_2 and NO_X emissions reductions required under today's rule. Section V, ''Determination of State Emissions Budgets,'' describes how EPA determined the State-by-State emissions reductions requirements and, in the event States elect to control EGUs, the State-by-State EGU emissions budgets. Section VI, ''Air Quality Modeling Approach and Results,'' describes the technical aspects of the air quality modeling and summarizes the numerical results of that modeling. Section VII, ''SIP Criteria and Emissions Reporting Requirements,'' describes the SIP submission date and other SIP requirements associated with the emissions controls that States might adopt. Section VIII, ''NO_X and SO_2 Model Cap and Trade Programs,'' describes the EPA administered cap and trade programs that States electing to control emissions from EGUs are encouraged to adopt. Section IX, ''Interactions with Other Clean Air Act Requirements,'' discusses how this rule interacts with the acid rain provisions in CAA title IV, the NO_X SIP Call, the best available retrofit technology (BART) requirements, and other CAA or regulatory requirements. Finally, section X, ''Statutory and Executive Order Reviews,'' describes the applicability of various administrative requirements for today's rule and how EPA addressed these requirements.

A. What Are the Central Requirements of This Rule?

In today's action, we establish SIP requirements for the affected upwind States under CAA section 110(a)(2). Clean Air Act section 110(a)(2)(D) requires SIPs to contain adequate provisions prohibiting air pollutant emissions from sources or activities in those States that contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to a NAAQS. Based on air

[5] Benefit and cost estimates reflect annual SO_2 and NO_X controls for Arkansas that are not a part of the final CAIR program. For this reason, these estimates are slightly overstated.

[6] Technical support document: ''Regional and State SO_2 and NO_X Emissions Budgets'' is included in the docket.

Technical support document: ''Air Quality Modeling'' is included in the docket.

[7] ''Response to Significant Comments on the Proposed Clean Air Interstate Rule'' is included in the docket.

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quality modeling analyses and cost analyses, EPA has concluded that SO_2 and NO_X emissions in certain States in the eastern part of the country, through the phenomenon of air pollution transport,[8] contribute significantly to downwind nonattainment, or interfere with maintenance, of the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA is requiring SIP revisions in 28 States and the District of Columbia to reduce SO_2 and/or NO_X emissions, which are important precursors of $PM_{2.5}$ (NO_X and SO_2) and ozone (NO_X).

The 23 States along with the District of Columbia that must reduce annual SO_2 and NO_X emissions for the purposes of the $PM_{2.5}$ NAAQS are: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

The 25 States along with the District of Columbia that must reduce NO_X emissions for the purposes of the 8-hour ozone NAAQS are: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. In addition to making the findings of significant contribution to nonattainment or interference with maintenance, EPA is requiring each State to make specified amounts of SO_2 and/or NO_X emissions reductions to eliminate their significant contribution to downwind States. The affected States and the District of Columbia are required to adopt and submit the required SIP revision with the necessary control measures by 18 months from the signature date of today's rule.

The emissions reductions requirements are based on controls that EPA has determined to be highly cost effective for EGUs. However, States have the flexibility to choose the measures to adopt to achieve the specified emissions reductions. If the State chooses to control EGUs, then it must establish a budget—that is, an emissions cap—for those sources. Today's rule defines the EGU budgets for each affected State if a State chooses to control only EGUs. The rule also explains the emission reduction requirements if a State chooses to achieve some or all of its required emission reductions by controlling sources other than EGUs. Due to feasibility constraints, EPA is requiring emissions reductions be implemented in two phases. The first phase of NO_X reductions starts in 2009 (covering 2009–2014) and the first phase of SO_2 reductions starts in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 starts in 2015 (covering 2015 and thereafter). For States subject to findings of significant contribution for $PM_{2.5}$, EPA is establishing annual emissions budgets. For States subject to findings of significant contribution for 8-hour ozone, the CAIR specifies ozone-season NO_X emissions budgets. States subject to findings for both $PM_{2.5}$ and ozone will have both an annual and an ozone season NO_X budget.

The EPA is providing, as an option to States, model cap and trade programs for EGUs. The EPA will administer these programs, which will be governed by rules provided by EPA that States may adopt or incorporate by reference.

With respect to federally recognized Indian Tribes, the applicability of this rule is governed by three factors: The flexible regulatory framework for Tribes provided by the CAA and the Tribal Authority Rule (TAR); the absence of any existing EGUs on Tribal lands in the CAIR region; and the existence of reservations within the geographic areas which we determined to contribute significantly to nonattainment areas.

Under CAA section 301(d) as implemented by the TAR, eligible Indian Tribes may implement all, but are not required to implement any, programs under the CAA for which EPA has determined that it is appropriate to treat Tribes similarly to States. Tribes may also implement ''reasonably severable'' elements of programs (40 CFR 49.7(c)). In the absence of Tribal implementation of a CAA program or programs, EPA will utilize Federal implementation for the relevant area of Indian country as necessary or appropriate to protect air quality, in consultation with the Tribal government.

The TAR contains a list of provisions for which it is not appropriate to treat Tribes in the same manner as States (40 CFR 49.4). The CAIR is based on the States' obligations under CAA section 110(a)(2)(D) to prohibit emissions which would contribute significantly to nonattainment in, or interfere with maintenance by, other States due to pollution transport. Because CAA section 110(a)(2)(D) is not among the provisions we determined to be inappropriate to apply to Tribes in the same manner as States, that section is applicable, where necessary and appropriate, to Tribes.

However, among the CAA provisions not appropriate for Tribes are ''[s]pecific plan submittal and implementation deadlines for NAAQS-related requirements * * *'' (40 CFR 49.4(a)). Therefore, Tribes are not required to submit implementation plans under section 110(a)(2)(D). Moreover, because no Tribal lands in the CAIR region currently contain any of the sources (EGUs) on which we based the emissions reductions requirements applicable to States, there are no emission reduction requirements applicable to Tribes.

At the same time, the existence of the CAIR cap and trade program in some or all of the affected States will have implications for any future construction of EGUs on Tribal lands. The geographic scope of the CAIR cap and trade program is being determined by a two step-process: the EPA's determination of which States significantly contribute to downwind areas, and the decision by those affected States whether to satisfy their emission reduction requirement by participating in the CAIR cap and trade program.

With respect to the first step of this process (significant contribution test), notwithstanding the political autonomy of Tribes, we view the zero-out modeling as representing the entire geographic area within the State being considered, regardless of the jurisdictional status of areas within the State. Therefore, any EGU constructed in the future on a reservation within a CAIR-affected State would be located in an area which we have already determined to significantly contribute to downwind nonattainment.[9]

With respect to decisions by States to participate in the CAIR cap and trade program, because Tribal governments are autonomous, such a decision would not be directly binding for any Tribe located within the State.

Nonetheless, as a matter of a policy, cap and trade programs by their nature must apply consistently throughout the geographic region of the program in order to be effective. Otherwise, the existence of areas not covered by the cap could create incentives to locate sources there, and thereby undermine

[8] In today's final rule, when we use the term ''transport'' we mean to include the transport of both fine particles ($PM_{2.5}$) and their precursor emissions and/or transport of both ozone and its precursor emissions.

[9] In this regard, the construction of a new EGU on a reservation would be analogous to the construction of a new EGU within a county or region of a CAIR-affected State that does not presently contain any EGUs. This is not meant to imply that Tribes are in any way legally similar to counties, only that, within the CAIR region, the geographic scale of reservations is more similar to counties than to States.

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the environmental goals of the program.[10]

In light of these considerations, in the event of any future planned construction of EGUs on Tribal lands within the CAIR region, EPA intends to work with the relevant Tribal government to regulate the EGU through either a Tribal implementation plan (TIP) or a Federal implementation plan (FIP). We anticipate that at a minimum, a proposed EGU on a reservation within a State participating in the CAIR cap and trade program would need to be made subject to the cap and trade program. In the case of a new EGU on a reservation in a CAIR-affected State which chose not to participate in the cap and trade program, the new EGU might also be required, through a TIP or FIP, to participate in the program. This would depend on the potential for emissions shifting and other specific circumstances (*e.g.*, whether the EGU would service the electric grid of States involved in the cap and trade program.) Again, EPA will work with the relevant Tribal government to determine the appropriate application of the CAIR.

Finally, as discussed in the SNPR, Tribes have objected to emissions trading programs that allocate allowances based on historic emissions, on the grounds that this rewards first-in-time emitters at the expense of those who have not yet enjoyed a fair opportunity to pursue economic development. Comments on the CAIR proposal from Tribes requested a Federal set-aside of allowances for Tribes, or other special Tribal allowance provisions. The few comments received from States on the issue generally opposed allocations based on Indian country status. One State expressed a willingness to share its emissions budget with Tribes in the event an EGU locates in Indian country.

The EPA does not believe there is sufficient information to design Tribal allocation provisions at this time. A program designed to address concerns which remain largely speculative is likely to create more problems through unintended consequences than it solves. Therefore, rather than create a Federal allowance set-aside for Tribes, EPA will work with Tribes and potentially affected States to address concerns regarding the equity of allowance allocations on a case-by-case basis as the need arises. The EPA may choose to revisit this issue through a separate rulemaking in the future.

B. Why Is EPA Taking This Action?

Emissions reductions to eliminate transported pollution are required by the CAA, as noted above. There are strong policy reasons for addressing interstate pollution transport.

1. Policy Rationale for Addressing Transported Pollution Contributing to $PM_{2.5}$ and Ozone Problems

Emissions from upwind States can alone, or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of residents in downwind communities. Control of $PM_{2.5}$ and ozone requires a reasonable balance between local and regional controls. If significant contributions of pollution from upwind States that can be abated by highly cost-effective controls are unabated, the downwind area must achieve greater local emissions reductions, thereby incurring extra clean-up costs. Requiring reasonable controls for both upwind and local emissions sources should result in achieving air quality standards at a lesser cost than a strategy that relies solely on local controls. For all these reasons, addressing interstate transport in advance of the time that States must adopt local nonattainment plans, will make it easier for States to develop their nonattainment plans because the States will know the degree to which the pollution flowing into their nonattainment areas will be reduced.

The EPA addressed interstate pollution transport for ozone in the NO_X SIP Call rule published in 1998.[11] Today's rulemaking is EPA's first attempt to address interstate pollution transport for $PM_{2.5}$. The NO_X SIP Call is substantially reducing ozone transport, helping downwind areas meet the 1-hour and 8-hour ozone standards. The EPA has reassessed ozone transport in this rulemaking for two reasons. First, several years have passed since promulgation of the NO_X SIP Call and updated air quality and emissions data are available. Second, some areas are expected to face substantial difficulty in meeting the 8-hour ozone standards. As a result, EPA has determined it is important to assess the degree to which ozone transport will remain a problem after full implementation of the NO_X SIP Call, and to assess whether further controls are warranted to ensure continued progress toward attainment. The modeling for the CAIR includes the NO_X SIP Call in the baseline and examines later years than the NO_X SIP Call analyses.

a. The $PM_{2.5}$ Problem

By action dated July 18, 1997, we revised the NAAQS for particulate matter (PM) to add new standards for fine particles, using as the indicator particles with aerodynamic diameters smaller than a nominal 2.5 micrometers, termed $PM_{2.5}$ (62 FR 38652). We established health- and welfare-based (primary and secondary) annual and 24-hour standards for $PM_{2.5}$. The annual standards are 15 micrograms per cubic meter, based on the 3-year average of annual mean $PM_{2.5}$ concentrations. The 24-hour standard is a level of 65 micrograms per cubic meter, based on the 3-year average of the annual 98th percentile of 24-hour concentrations. The annual standard is generally considered the most limiting.

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems such as heart attacks and cardiac arrhythmia. The EPA has estimated that attainment of the $PM_{2.5}$ standards would prolong tens of thousands of lives and would prevent, each year, tens of thousands of hospital admissions as well as hundreds of thousands of doctor visits, absences from work and school, and respiratory illnesses in children.

Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children. More detailed information on health effects of fine particles can be found on EPA's Web site at: *http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_index.html.*

At the time EPA established the $PM_{2.5}$ primary NAAQS in 1997, we also established welfare-based (secondary) NAAQS identical to the primary standards. The secondary standards are designed to protect against major environmental effects caused by PM such as visibility impairment—including in Class I areas which include national parks and wilderness areas across the country—soiling, and materials damage.

[10] Although it is possible that the CAIR cap and trade program may cover a discontinuous area depending on which States participate, the failure of a State to participate does not raise the same environmental integrity concern. A state that does not participate in the cap and trade program must still submit a SIP that limits emissions to the levels mandated by the CAIR emission reduction requirements, taking into account any emissions from new sources.

[11] "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," (63 FR 57356; October 27, 1998).

As discussed in other sections of this preamble, SO_2 and NO_X emissions both contribute to fine particle concentrations. In addition, NO_X emissions contribute to ozone problems, described in the next section. We believe the CAIR will significantly reduce SO_2 and NO_X emissions that contribute to the $PM_{2.5}$ and 8-hour ozone problems described here.

The $PM_{2.5}$ ambient air quality monitoring for the 2001–2003 period shows that areas violating the standards are located across much of the eastern half of the United States and in parts of California, and Montana. Based on these nationwide data, 82 counties have at least one monitor that violates either the annual or the 24-hour $PM_{2.5}$ standard. Most areas violate only the annual standard; a small number of areas violate both the annual and 24-hour standards; and no areas violate just the 24-hour standard. The population of these 82 counties totals over 56 million people.

Only two States in the western part of the U.S., California and Montana, have counties that exceeded the $PM_{2.5}$ standards. On the other hand, in the eastern part of the U.S., 124 sites in 69 counties (with total population of 34 million) violated the annual $PM_{2.5}$ standard of 15.0 micrograms per cubic meter ($\mu g/m^3$) over the 3-year period from 2001 to 2003, while 469 sites met the annual standard. No sites in the eastern part of the United States exceeded the daily $PM_{2.5}$ standard of 65 $\mu g/m^3$. The 69 violating counties are located in a region made up of 16 States (plus the District of Columbia), extending eastward from St. Louis County, Missouri, the western-most violating county and including the following States: Alabama, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Missouri, Michigan, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. The EPA published the $PM_{2.5}$ attainment and nonattainment designations on January 5, 2005 (70 FR 944). The designations will be effective on April 5, 2005.

Because interstate transport is not believed to be a significant contributor to exceedances of the $PM_{2.5}$ standards in California or Montana, today's final CAIR does not cover these States.

b. The 8-Hour Ozone Problem

By action dated July 18, 1997, we promulgated identical revised primary and secondary ozone standards that specified an 8-hour ozone standard of 0.08 parts per million (ppm). Specifically, under the standards, the 3-year average of the fourth highest daily maximum 8-hour average ozone concentration may not exceed 0.08 ppm. In general, the revised 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards. All areas that were violating the 1-hour ozone standard at the time of the 8-hour ozone designations were also designated as nonattainment for the 8-hour ozone standard. More areas do not meet the 8-hour standard than do not meet the 1-hour standard. The EPA published the 8-hour ozone attainment and nonattainment designations in the **Federal Register** on April 30, 2004 (69 FR 23858). The designations were effective on June 15, 2004. Pursuant to EPA's final rule to implement the 8-hour ozone standard (69 FR 23951; April 30, 2004), EPA will revoke the 1-hour ozone standard on June 15, 2005, 1 year after the effective date of the 8-hour designations.

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. Short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, a lifetime).

People who are particularly susceptible to the effects of ozone include children and adults who are active outdoors, people with respiratory diseases, such as asthma, and people with unusual sensitivity to ozone.

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.*, harsh weather). In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems. Ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. The economic value of some welfare losses due to ozone can be calculated, such as crop yield loss from both reduced seed production (*e.g.*, soybean) and visible injury to some leaf crops (*e.g.*, lettuce, spinach, tobacco), as well as visible injury to ornamental plants (*i.e.*, grass, flowers, shrubs). Other types of welfare loss may not be quantifiable (*e.g.*, reduced aesthetic value of trees growing in heavily visited national parks). More detailed information on health effects of ozone can be found at the following EPA Web site: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*.

Almost all areas of the country have experienced some progress in lowering ozone concentrations over the last 20 years. As reported in the EPA's report, "The Ozone Report: Measuring Progress Through 2003," [12] national average levels of 1-hour ozone improved by 29 percent between 1980 and 2003 while 8-hour levels improved by 21 percent over the same time period. The Northeast and West regions have shown the greatest improvement since 1980. However, most of that improvement occurred during the first part of the period. In fact, during the most recent 10 years, ozone levels have been relatively constant reflecting little if any air quality improvement. For this reason, ozone has exhibited the slowest progress of the six major pollutants tracked nationally.

Although ambient ozone levels remained relatively constant over the past decade, additional control requirements have reduced emissions of the two major ozone precursors, VOC and NO_X, although at different rates. Emissions of VOCs were reduced by 32 percent from 1990 levels, while emissions of NO_X declined by 22 percent.

Ozone remains a significant public health concern. Presently, wide geographic areas, including most of the nation's major population centers, experience unhealthy ozone levels, that is, concentrations violating the NAAQS for 8-hour ozone. These areas include much of the eastern part of the United States and large areas of California. More specifically, 297 counties with a total population of over 124 million people currently violate the 8-hour ozone standard. Most of these ozone

[12] EPA 454/K–04–001, April 2004.

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violations occur in the eastern half of the United States: 268 counties with a population of over 93 million.

When ozone and $PM_{2.5}$ are examined jointly, 322 counties with 131 million people are violating at least one of the standards while 57 counties nationwide have concentrations violating both standards with a total population of over 49 million people. Of these, 46 counties with a population of over 28 million are in the Eastern United States.

c. Other Environmental Effects Associated With SO_2 and NO_X Emissions

Today's action will result in benefits in addition to the enumerated human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone. Reductions in NO_X and SO_2 will contribute to substantial visibility improvements in many parts of the Eastern U.S. where people live, work, and recreate, including Federal Class I areas such as the Great Smoky Mountains. Reductions in these pollutants will also reduce acidification and eutrophication of water bodies in the region. In addition, reduced mercury emissions are anticipated as a result of this rule. Reduced mercury emissions will lessen mercury contamination in lakes and thereby potentially decrease both human and wildlife exposure to mercury-contaminated fish.

2. The CAA Requires States To Act as Good Neighbors by Limiting Downwind Impacts

The CAA includes the ''good neighbor'' provision of section 110(a)(2)(D), which requires that every SIP prohibit emissions from any source or other type of emissions activity in amounts that will contribute significantly to nonattainment in any downwind State, or that will interfere with maintenance in any downwind State. In today's action, EPA is determining that 28 States and the District of Columbia, all in the eastern part of the United States, have emissions of SO_2 and/or NO_X that will contribute significantly to nonattainment, or interfere with maintenance, of the $PM_{2.5}$ NAAQS and/or the 8-hour ozone NAAQS in another State. Under EPA's general authority to clarify the applicability of CAA requirements, as provided in CAA section 301(a)(1), EPA is establishing the amount of SO_2 and NO_X emissions that each affected State must prohibit by submitting appropriate SIP provisions to EPA. The improvements in air quality will assist downwind States in developing their SIPs to provide for attainment and maintenance in those nonattainment areas.

3. Today's Rule Will Improve Air Quality

The EPA has estimated the improvements in emissions and air quality that would result from implementing the CAIR. These improvements, which are substantial, are summarized earlier in this section.

C. What Was the Process for Developing This Rule?

By action dated January 30, 2004, EPA issued a proposal that included many of the components of today's action. ''Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule,'' (69 FR 4566). The Administrator signed the proposed rule—termed, at that time, the Interstate Air Quality Rule—on December 17, 2003, and EPA posted it on its Web site for this rule on that date. The Web site address at that time was *http://www.epa.gov/interstateairquality*. (The address has since changed to *http://www.epa.gov/cleanairinterstaterule/* or *http://www.epa.gov/cair/*.)

The EPA held public hearings on the proposal, in conjunction with a proposed rulemaking concerning mercury and other hazardous air pollutants from EGUs, on February 25–26, 2004, in Chicago, Illinois; Philadelphia, Pennsylvania; and Research Triangle Park, North Carolina. The comment period for the NPR closed on March 30, 2004. The EPA received over 6,700 comments on the proposal.

By action dated June 10, 2004, EPA issued a supplemental notice of proposed rulemaking (SNPR), ''Supplemental Proposal for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Proposed Rule,'' (69 FR 32684). The Administrator signed the SNPR for this rule—now called the Clean Air Interstate Rule—on May 18, 2004, and EPA placed it on the Web site on that date. The SNPR included, among other things, proposed regulatory language for the rule, revised proposals concerning State-level emissions budgets, proposed State reporting requirements and SIP approvability criteria, and proposed model cap and trade rules. The SNPR also proposed that under certain circumstances the CAIR requirements could replace the BART requirements of CAA sections 169A and 169B. The EPA held a public hearing on the SNPR on June 3, 2004, in Alexandria, Virginia. The comment period for the SNPR closed on July 26, 2004. The EPA received over 400 comments on the SNPR.

By a notice of data availability (NODA) dated August 6, 2004, EPA announced the availability of additional documents for this action. ''Availability of Additional Information Supporting the Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule),'' (69 FR 47828). The documents had been placed on the website on or about July 27, 2004, and in the EDOCKET on that date, or shortly thereafter. The EPA allowed public comment on those additional documents until August 27, 2004. Around 30 comments were received on the NODA.

The EPA has responded to all significant public comments either in this preamble or in the response to comment document which is contained in the docket.

Comments on Rulemaking Process: Some commenters expressed concerns about certain aspects of this process. One concern was that EPA did not allow sufficient time to comment on the SNPR. Commenters noted that important program elements—including regulatory language—appeared for the first time in the SNPR, but EPA held a public hearing on the SNPR 7 days before the SNPR was published in the **Federal Register** and only 16 days after the SNPR had been posted on the website. The EPA believes that the 16-day period preceding the public hearing, and the total of 45 days to comment on the SNPR following its publication in the **Federal Register**, constituted an adequate opportunity for members of the public to comment on the SNPR.

Commenters also expressed concern that certain technical documents were not made available in sufficient time to comment. However, EPA had placed all technical support documents for the NPR in the EDOCKET as of the date of publication of the NPR, and all technical support documents for the SNPR had been placed in the EDOCKET as of the date of publication of the SNPR.

Commenters also expressed concern that in the SNPR, EPA proposed significant changes to other regulatory programs. The EPA agrees that the SNPR did include proposed changes to certain regulatory programs, *i.e.*, the requirements for BART under CAA sections 169A and 169B (concerning visibility), certain provisions (primarily concerning the allowance-holding requirement) in the title IV (Acid Rain Program) rules, and certain emissions reporting rules under the NO_X SIP Call (40 CFR 51.122) and Consolidated

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Emissions Reporting Rule (CERR) (title 40, part 51, subpart A). The EPA believes that to the extent the requirements for BART and emissions reporting rule revisions are tied to the CAIR, affected members of the public had adequate notice of those revisions. (These revisions are described in section VII.) However, the SNPR contained some revisions to the emissions reporting rules that were not tied to the transport provisions. The EPA is not taking final action today on the proposal for the emissions reporting rules that were not tied to the transport provisions and instead is issuing a new proposal for them, which will provide additional notice and opportunity to comment.

Further, the Acid Rain Program rule revisions, although connected to the CAIR, apply to all persons subject to the Acid Rain Program, including persons who are not affected by the CAIR. (These revisions are described in section IX.) Specifically, as explained in section IX, the revisions to the Acid Rain Program rules are aimed at facilitating coordination of the Acid Rain Program and the CAIR model SO_2 cap and trade rule and/or are being adopted on their own merits, independently of the need to coordinate with the CAIR. Most of the proposed revisions involve changing from unit-by-unit to source-by-source compliance with the allowance-holding requirement of the Acid Rain Program and therefore affect every source subject to the Acid Rain Program, whether or not the source is also in a State covered by the CAIR. The change to source-by-source compliance increases a source's flexibility to use—in meeting the allowance-holding requirement—allowances held by any unit at the source. This flexibility reduces the likelihood that sources will incur large excess emissions penalties from inadvertent, minor errors (*e.g.*, in how allowances are distributed among the units at the source), while preserving the environmental goals of the Acid Rain Program. The remaining revisions to the Acid Rain Program rules similarly cover all Acid Rain Program sources. Indeed, none of the comments on the proposed Acid Rain Program rule revisions stated that the revisions would apply only to certain Acid Rain Program sources, but rather seemed to treat the revisions as applying program-wide. As discussed in section IX, EPA is finalizing, with minor modifications, the Acid Rain Program rule revisions.

Commenters also expressed concern that between the NPR and the SNPR, EPA had proposed program elements in a piecemeal fashion, which made it more difficult to comprehend and comment on the rule, and that the SNPR's comment period was too short to allow the public adequate opportunity to comment on the numerous and complex issues raised in that proposal. The EPA recognizes the challenges faced by commenters in this rulemaking, however, we believe that the comment periods for the NPR and SNPR were adequate, and note that we did receive extensive and highly detailed, technical comments on both proposals.

D. What Are the Major Changes Between the Proposals and the Final Rule?

The EPA is finalizing a number of revisions to the proposed elements of the CAIR. These revisions are in response to information received in public comments and new analyses conducted by EPA. The following is a summary list of those changes:

- The first phase of NO_X reductions starts in 2009 (covering 2009–2014) instead of 2010. The first phase of the SO_2 reductions still starts in 2010 (covering 2010–2014).
- The emissions inventories used for $PM_{2.5}$ and 8-hour ozone air quality modeling have been updated and improved; we modeled $PM_{2.5}$ using the Community Multiscale Air Quality Model (CMAQ) and meteorology for 2001 instead of the Regional Model for Simulating Aerosols and Deposition (REMSAD) and meteorology for 1996.
- The final CAIR does not cover Kansas based on new analyses of its contribution to downwind $PM_{2.5}$ nonattainment.
- Arkansas, Delaware, Massachusetts, and New Jersey are not subject to the CAIR based on their contribution to $PM_{2.5}$ nonattainment and maintenance. However, they remain subject to NO_X emissions reductions requirements on the basis of their contribution to downwind 8-hour ozone nonattainment. This requirement is for the ozone season rather than the entire year. The EPA is issuing a new proposal to include Delaware and New Jersey for the $PM_{2.5}$ NAAQS based on additional considerations.
- The change in States covered by the rule necessitates a re-analysis of the NO_X budgets for all covered States. This changes the amount of the budget, but not the procedure EPA used to calculate it.
- The SIP approval criteria have been changed to no longer exclude measures otherwise required by the CAA from being included in the State's compliance with CAIR.
- A 200,000 ton compliance supplement pool was added for NO_X. Allowances from this pool can either be awarded to sources that make early reductions or to sources that demonstrate need.
- All States for which EPA has made a finding with respect to ozone are subject to an ozone season cap. In order to implement this ozone season cap, EPA has finalized an ozone season NO_X trading program in addition to the annual NO_X and SO_2 trading programs that were proposed.
- A number of changes were made to the trading rule including: changes to the model NO_X allocation methodology (to fuel weight allocations) and the addition of opt in provisions.
- The EPA is not finalizing some of the emissions reporting requirements in response to public comments indicating we gave inadequate notice of the changes that were proposed to be applicable to all States, not just those affected by the CAIR emission reduction requirements. These are being reproposed, with modifications, in a separate action to allow additional opportunity for public comment by all affected States and other parties.

II. The EPA's Analytical Approach

Overview: Today's rulemaking is based on the ''good neighbor'' provision of CAA section 110(a)(2)(D), which requires States to develop SIP provisions assuring that emissions from their sources do not contribute significantly to downwind nonattainment, or interfere with maintenance, of the NAAQS. The EPA interpreted this provision, and developed a detailed methodology for applying it, in the NO_X SIP Call rulemaking, which concerned interstate transport of ozone precursors.

Today's rule requires upwind States to submit SIP revisions requiring their sources to reduce emissions of certain precursors that significantly contribute to nonattainment in, or interfere with maintenance of, the $PM_{2.5}$ and 8-hour ozone national ambient air quality standards in downwind States. The EPA developed today's rule relying heavily on the NO_X SIP Call approach.

This section of the preamble outlines the key aspects of today's approach, some of which are described in greater detail in other sections of the preamble. The EPA received comments on today's approach that we respond to either in this section or in the other sections of the preamble. This section also describes how today's approach varies from the NO_X SIP Call, which variations result from, among other things, the fact that today's action regulates a different pollutant ($PM_{2.5}$) with a different precursor (SO_2).

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A. How Did EPA Interpret the Clean Air Act's Pollution Transport Provisions in the NO_X SIP Call?

1. Clean Air Act Requirements

The central CAA provisions concerning pollutant transport, for purposes of today's action, are found in section 110(a)(2)(D). Under these provisions, each SIP must—

(D) Contain adequate provisions

(i) Prohibiting * * * any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

(I) Contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any * * * national primary or secondary ambient air quality standard * * *.

2. The NO_X SIP Call Rulemaking

Promulgated by action dated October 27, 1998, the NO_X SIP Call was EPA's principal effort to reduce interstate transport of precursors for both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS. (See ''Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule,'' (63 FR 57356).) In that rulemaking, EPA imposed seasonal NO_X reduction requirements on 22 States and the District of Columbia in the eastern part of the country.

a. Analytical Approach of NO_X SIP Call

In the NO_X SIP Call, EPA interpreted section 110(a)(2)(D) to authorize EPA to determine the amount of emissions in upwind States that ''contribute significantly'' to downwind nonattainment or ''interfere with'' downwind maintenance, and to require those States to eliminate that amount of emissions. The EPA recognized that States must retain full authority to choose the sources to control, and the control mechanisms, to achieve those reductions.

The EPA set out several criteria or factors for the ''contribute significantly'' test, and further indicated that the same criteria should apply to the ''interfere with maintenance'' provision: [13]

* * * EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind State primarily by (i) evaluating, with respect to each upwind State, several air quality related factors, including determining that all emissions from the State have a sufficiently great impact downwind (in the context of the collective contribution nature of the ozone problem); and (ii) determining the amount of that State's emissions that can be eliminated through the application of cost-effective controls. Before reaching a conclusion, EPA evaluated several secondary, and more general, considerations. These include:

• The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems.

• The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas.

• General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls.

63 FR 57403

i. Air Quality Factor

The first factor concerns evaluating the impact on downwind air quality of the upwind State's emissions. As EPA stated in the NO_X SIP Call: * * *

EPA specifically considered three air quality factors with respect to each upwind State * * *.

• The overall nature of the ozone problem (*i.e.*, ''collective contribution'').

• The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas.

• The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems.

63 FR 57376

The EPA explained the first factor, collective contribution, by noting,

[V]irtually every nonattainment problem is caused by numerous sources over a wide geographic area* * *[. This] factor suggest[s] that the solution to the problem is the implementation over a wide area of controls on many sources, each of which may have a small or unmeasureable ambient impact by itself.

63 FR 57377

The second air quality factor—the extent of downwind nonattainment problems—concerns whether downwind areas should be considered to be in nonattainment. This determination took into account the then-current air quality of the area, the predicted future air quality (assuming the implementation of required controls, but not the transport requirements that were the subject of the NO_X SIP Call), and the boundaries of the area in light of designation status (63 FR 57377).

The EPA applied the third air quality factor—the ambient impact of emissions from the upwind sources—by projecting the amount of the upwind State's entire inventory of anthropogenic emissions to the year 2007, and then quantifying, through the appropriate air quality modeling techniques, the impact of those emissions on downwind nonattainment.[14] Specifically, (i) EPA determined the minimum threshold impact that the upwind State's emissions must have on a downwind nonattainment area to be considered potentially to contribute significantly to nonattainment; and then (ii) for States with impacts above that threshold, EPA developed a set of metrics for further evaluating the contribution of the upwind State's emissions on a downwind nonattainment area (63 FR 57378). The EPA considered a State with emissions that had a sufficiently great impact to contribute significantly to the downwind area (depending on application of the cost factor). In general, EPA established the thresholds at a relatively low level, which reflected the collective contribution phenomenon. That is, because the ozone problem is caused by many relatively small contributions, even relatively small contributors must participate in the solution.

ii. Cost Factor

The cost factor is the second major factor that EPA applied to determine the significant contribution to nonattainment: ''EPA * * * determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective.'' (*See* 63 FR 57377.)

(I) Choice of Highly Cost-Effective Standard

The EPA selected the standard of highly cost effective in order to assure State flexibility in selecting control strategies to meet the emissions reduction requirements of the rulemaking. That is, the rulemaking required the States to achieve specified levels of emissions reductions—the levels achievable if States implemented the control strategies that EPA identified

[13] In the NO_X SIP Call, because the same criteria applied, the discussion of the ''contribute significantly to nonattainment'' test generally also applied to the ''interfere with maintenance'' test. However, in the NO_X SIP Call, EPA stated that the ''interfere with maintenance'' test applied with respect to only the 8-hour ozone NAAQS (63 FR 57379–80).

[14] Although EPA's air quality modeling techniques examined all of the upwind State's emissions of ozone precursors (including VOC and NO_X), only the NO_X emissions had meaningful interstate impacts.

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as highly cost effective—but the rulemaking did not mandate those highly cost-effective control strategies, or any other control strategy. Indeed, in calculating the amount of the required emissions reductions by assuming the implementation of highly cost-effective control strategies, EPA assured that other control strategies—ones that were cost effective, if not highly cost effective—remained available to the States.

(II) Determination of Highly Cost-Effective Amount

The EPA determined the dollar amount considered to be highly cost effective by reference to the cost effectiveness of recently promulgated or proposed NO_X controls. The EPA determined that the average cost effectiveness of controls in the reference list ranged up to approximately $1,800 per ton of NO_X removed (1990$), on an annual basis. The EPA considered the controls in the reference list to be cost effective.

The EPA established $2,000 (1990$) in average cost effectiveness for summer ozone season emissions reductions as, at least directionally, the highly cost-effective amount. Identifying this amount on an ozone season basis was appropriate because the NO_X SIP Call concerned the ozone standard, for which emissions reductions during only the summer ozone season are necessary. This level of costs reflected the fact that in general, States with downwind ozone nonattainment areas had already implemented extensive controls. Accordingly, it was evident that the level of upwind controls EPA selected would prove necessary for the downwind areas to reach attainment.

(III) Source Categories

The EPA then determined that the source categories for which highly cost-effective controls were available included EGUs, large industrial boilers and turbines, and cement kilns. At the same time, EPA determined, for those source categories, the level of controls that would cost an amount consistent with the highly cost-effective amount and that would be feasible. The EPA considered other source categories, but found that highly cost-effective controls were not available from them for various reasons, including the size of the sources, the relatively small amount of emissions from the sources, or the control costs.

iii. Other Factors

The EPA also relied on several other, secondary considerations before concluding that the identified amount of emissions reductions were required. The first concerned the consistency of regional reductions with downwind attainment needs. The EPA ascertained the ozone air quality impacts of the required emissions reductions, and determined that those impacts improved air quality downwind, but not to the point that would raise questions about whether the amount of reductions was more than necessary (63 FR 57379).

The second general consideration was ''the overall fairness of the control regimes'' to which the downwind and upwind areas were subject. The EPA explained:

> Most broadly, EPA believes that overall notions of fairness suggest that upwind sources which contribute significant amounts to the nonattainment problem should implement cost-effective reductions. When upwind emitters exacerbate their downwind neighbors' ozone nonattainment problems, and thereby visit upon their downwind neighbors additional health risks and potential clean-up costs, EPA considers it fair to require the upwind neighbors to reduce at least the portion of their emissions for which highly cost-effective controls are available.
>
> In addition, EPA recognizes that in many instances, areas designated as nonattainment under the 1-hour NAAQS have incurred ozone control costs since the early 1970s. Moreover, virtually all components of their NO_X and VOC inventories are subject to SIP-required or Federal controls designed to reduce ozone. Furthermore, these areas have complied with almost all of the specific control requirements under the CAA, and generally are moving towards compliance with their remaining obligations. The CAA's sanctions and FIP provisions provide assurance that these remaining controls will be implemented. By comparison, many upwind States in the midwest and south have had fewer nonattainment problems and have incurred fewer control obligations.

(63 FR 57379.)

The third general consideration was ''general cost considerations.'' The EPA noted that ''in general, areas that currently have, or that in the past have had, nonattainment problems * * * have already incurred ozone control costs.'' The next set of controls available to these nonattainment areas would be more expensive than the controls available to the upwind areas. The EPA found that this cost scenario further confirmed the reasonableness of the upwind control obligations (63 FR 57379).

In the NO_X SIP Call, EPA considered all of these factors together in determining the level of controls considered to be highly cost effective. This level of controls reflected the then-present state of ozone controls: Within the region, the nonattainment areas were already required to—and had already implemented—VOC and NO_X controls that covered much of their inventory. However, the upwind States in the region generally had not done so (except to the extent of their ozone nonattainment areas). In this context, EPA considered it reasonable to impose an additional control burden on the upwind States. Air quality modeling showed that even with this additional level of upwind controls, residual nonattainment remained, so that further reductions from downwind and/or upwind areas would be necessary.

b. Regulatory Requirements

After ascertaining the controls that qualified as highly cost effective, EPA developed a methodology for calculating the amount of NO_X emissions that each State was required to reduce on grounds that those emissions contribute significantly to nonattainment downwind. The total amount of required NO_X emissions reductions was the sum of the amounts that would be reduced by application of highly cost-effective controls to each of the source categories for which EPA determined that such controls were available (63 FR 57378).

The largest of these source categories was EGUs. The EPA determined the amount of reductions associated with EGU controls by applying the control rate that EPA considered to reflect highly cost-effective controls to each State's EGU heat input. That heat input, in turn, was adjusted to reflect projected growth.

Each affected State retained the authority to achieve the required level of reductions by implementing whatever controls on whatever sources it wished, and EPA determined that there were other source categories for which cost-effective, if not highly cost-effective, controls were available (63 FR 57378). If the States chose to control EGUs, then the NO_X SIP Call mandated certain requirements—including a statewide cap on EGU NO_X emissions—but also made available an EPA-administered regionwide EGU allowance trading program that the States could choose to adopt.

c. SIP Submittal and Implementation Requirements

At the time EPA promulgated the NO_X SIP Call, States already had SIPs for the 1-hour ozone NAAQS in place. In the NO_X SIP Call, EPA determined that the 1-hour SIPs for the affected States were deficient, and EPA called on these States, under CAA section 110(k)(5), to submit, within 12 months of promulgation of the NO_X SIP Call, SIP revisions to cure the deficiency by complying with the NO_X SIP Call

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regulatory requirements. The EPA further required that the NO_X SIP Call-required controls be implemented as expeditiously as practicable. The EPA determined this date to be within 3 years of the SIP submittal date (with that period extended to the beginning of the next ozone season), in light of the various constraints that EGUs would confront in implementing controls.

For the SIPs due under the 8-hour ozone NAAQS, in the NO_X SIP Call, EPA did not incorporate a section 110(k)(5) SIP call, but instead required States to submit, under section 110(a)(1)–(2), SIP revisions to fulfill the requirements of section 110(a)(2)(D). The EPA required these 8-hour ozone SIPs to be submitted—and the controls mandated therein to be implemented—on the same schedule as the 1-hour SIPs.

However, EPA stayed the 8-hour ozone requirements of the NO_X SIP Call, due to litigation concerning the 8-hour ozone NAAQS. To date, EPA has not lifted that stay.

3. *Michigan* v. *EPA* Court Case

Petitioners brought legal challenges to various components of the NO_X SIP Call's analytical approach in the United States Court of Appeals for the District of Columbia Circuit, in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir., 2000), *cert. denied,* 532 U.S. 904 (2001). The Court upheld the essential features of the air quality modeling part of EPA's approach, *id.* at 673; as well as EPA's definition of ''contribute significantly'' to include the factor of highly cost-effective controls, *id.* at 679. The Court did vacate or remand certain specific applications of EPA's approach, and delayed the implementation date to May 31, 2004. *See, e.g., id.* at 67, 681–85, 692–94. In addition, in a subsequent case that reviewed separate EPA rulemakings making technical corrections to the NO_X SIP Call, the DC Circuit remanded for a better explanation EPA's methodology for computing the growth component in the EGU heat input calculation. *Appalachian Power Co.* v. *EPA,* 251 F.3d 1026 (DC Cir., 2001).[15]

4. Implementation of the NO_X SIP Call

The court decisions left intact most of the NO_X SIP Call requirements. All States subject to those requirements—which EPA has termed the NO_X SIP Call Phase I requirements—submitted SIPs incorporating them, and requiring control implementation by May 31, 2004 or earlier. The EPA has approved those SIPs.

The EPA responded to the DC Circuit's EGU growth remand decisions through a **Federal Register** action that provided a more detailed explanation and other supporting information for the EGU growth methodology (67 FR 21868; May 1, 2002). The Court subsequently upheld that explanation. *West Virginia* v. *EPA,* 362 F.3d 861 (DC Cir. 2004). In addition, by action dated April 21, 2004, EPA promulgated a rulemaking that responded to other remanded and vacated issues, and included the remaining requirements—termed the NO_X SIP Call Phase II requirements—for the affected States (69 FR 21604).

B. How Does EPA Interpret the Clean Air Act's Pollution Transport Provisions in Today's Rule?

1. CAIR Analytical Approach

Today, EPA adopts much the same interpretation and application of section 110(a)(2)(D) for regulating downwind transport of precursors of $PM_{2.5}$ and 8-hour ozone as EPA adopted for the NO_X SIP Call. We are adjusting some aspects of the NO_X SIP Call analytic approach for various reasons, including the need to account for regulation of a different pollutant ($PM_{2.5}$) with an additional precursor (SO_2).

a. Nature of Nonattainment Problem and Overview of Today's Approach

As described in section I, above, the interstate transport component of current nonattainment of the $PM_{2.5}$ and 8-hour ozone NAAQS is primarily confined to the eastern part of the country, although in an area that is larger, by several States, than the area that EPA focused on in the NO_X SIP Call for only ozone. As described in section III, it is evident that local controls alone cannot be counted on to solve the nonattainment problems, although uncertainties remain in the state of knowledge of these nonattainment problems as well as the precise role interstate and local controls should play. As in the case of the NO_X SIP Call, it is not reasonable to expect a local area to bear the entire burden of solving the air quality problems, even if doing so were technically possible.

Turning to the interstate component of the nonattainment problems, as discussed in section III below, for $PM_{2.5}$, we find sufficient information is available to address the adverse downwind impacts caused by SO_2 and NO_X, and to develop emissions reductions requirements for SO_2 and NO_X. However, we do not have sufficient information to address other precursors. As discussed in section III below, for 8-hour ozone, we reiterate the finding of the NO_X SIP Call that NO_X emissions, and not VOC emissions, are of primary importance for interstate transport purposes.

We interpret CAA section 110(a)(2)(D) to require SIPs in upwind States to eliminate the amounts of emissions that contribute significantly to downwind nonattainment or interfere with downwind maintenance. As described below, in today's rule, EPA determines that upwind States' emissions contribute significantly to nonattainment or interfere with maintenance of the $PM_{2.5}$ NAAQS.

To quantify the amounts of those emissions that contribute significantly to nonattainment, we primarily focus on the air quality factor reflecting the upwind State's ambient impact on downwind nonattainment areas, and the cost factor of highly cost-effective controls. However, as with the NO_X SIP Call, EPA also considers other factors, which serve to establish the broad context for applying the air quality and cost factors. Today, we adopt the formulation of those factors as described in the CAIR NPR, which has little conceptual difference from EPA's application of those factors in the NO_X SIP Call.

Discussion of issues relating to maintenance are found in section III below.

b. Air Quality Factor

i. $PM_{2.5}$

With respect to the $PM_{2.5}$ NAAQS, as described in section VI, we employed air quality modeling techniques to assess the impact of each upwind State's entire inventory of anthropogenic SO_2 and NO_X emissions on downwind nonattainment and maintenance. For air quality and technical reasons described below, EPA determined that upwind SO_2 and NO_X emissions contribute significantly to nonattainment as of the year 2010. Therefore, EPA projected SO_2 and NO_X emissions to the year 2010, assuming certain required controls (but not controls required under CAIR), and then modeled the impact of those projected emissions (termed the base case inventory) on downwind $PM_{2.5}$ nonattainment in that year.

As discussed in section III, we adopt today a threshold air quality impact of 0.2 $\mu g/m^3$, so that an upwind State with contributions to downwind nonattainment below this level would

[15] By action dated January 18, 2000, EPA promulgated another rulemaking that was related to the NO_X SIP Call, known as the section 126 Rule (65 FR 2675). The DC Circuit generally upheld this rule, although it remanded for better explanation the EGU heat input growth methodology. *Appalachian Power Co.* v. *EPA.* 249 F. 3d 1032 (DC Cir., 2001).

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not be subject to regulatory requirements, but a State with contributions at or higher than this level would be subject to further evaluation.

Because of the inherent differences between the $PM_{2.5}$ and ozone NAAQS, this threshold necessarily differs from the threshold chosen for the NO_X SIP Call in terms of: (i) The metrics selected to evaluate the threshold, and (ii) the specific level of the threshold. Even so, the threshold EPA proposed for $PM_{2.5}$ is generally consistent with the approach taken in the NO_X SIP Call for the threshold level for ozone in that both are relatively low. This level reflects the fact that $PM_{2.5}$ nonattainment, like ozone, is caused by many sources in a broad region, and therefore may be solved only by controlling sources throughout the region. As with the NO_X SIP Call, the collective contribution condition of $PM_{2.5}$ air quality is reflected in the proposed relatively low threshold.[16]

The EPA determined that as of 2010, 23 upwind States and the District of Columbia will have contributions to downwind $PM_{2.5}$ nonattainment areas that are sufficiently high to meet the air quality factor of the transport test.

ii. 8-Hour Ozone

With respect to the 8-hour ozone NAAQS, we also employed, as described in section VI, air quality modeling techniques to assess the impact of each upwind State's entire inventory of NO_X and VOC emissions on downwind nonattainment. The EPA determined that upwind NO_X emissions contribute significantly to 8-hour ozone nonattainment as of the year 2010. Therefore, EPA projected NO_X emissions to the year 2010, assuming certain required controls (but not controls required under CAIR), and then modeled the impact of those projected emissions (termed the base case inventory) on downwind 8-hour ozone nonattainment in that year.

For the 8-hour ozone air quality factor, EPA employs the same threshold amounts and metrics that it used in the NO_X SIP Call. That is, as described in section VI, emissions from an upwind State contribute significantly to nonattainment if the maximum contribution is at least 2 parts per billion, the average contribution is greater than one percent, and certain other numerical criteria are met.

[16] The second air quality factor described in the NO_X SIP Call—the extent of downwind nonattainment—is reflected in the identification of downwind $PM_{2.5}$ nonattainment areas, discussed elsewhere in today's final action. The third air quality factor—the ambient impact of upwind emissions—is reflected in the threshold level.

The EPA determined that as of 2010, 25 upwind States and the District of Columbia will have contributions to downwind nonattainment areas that are sufficiently high to meet the air quality factor of the transport test.

c. Cost Factor

The second major factor that EPA applies is the cost factor. As in the case of the NO_X SIP Call, EPA interprets this factor as mandating emissions reductions in amounts that would result from application of highly cost-effective controls. We ascertain the level of costs as highly cost effective by reference to the cost effectiveness of recent controls. As we stated in the CAIR NPR, in determining the appropriate level of controls, we considered feasibility issues—as we did in the NO_X SIP Call—specifically, ''the applicability, performance, and reliability of different types of pollution control technologies for different types of sources; * * * and other implementation costs of a regulatory program for any particular group of sources.'' (*See* CAIR NPR, 69 FR 4585.)

As described in section IV, today we conclude that at present, EGUs are the only source category for which highly cost-effective SO_2 and NO_X controls are available. In making this determination, we examined what information is available concerning which source categories emit relatively large amounts of emissions, and what difficulties sources have in implementing controls. These criteria are similar to those considered in the NO_X SIP Call.

As discussed in section IV, for $PM_{2.5}$, today's action finalizes our proposal to identify as highly cost effective the dollar amount of cost effectiveness that falls near the low end of the reference range for both annual SO_2 controls and annual NO_X controls. We identify this level based on the overall context of the $PM_{2.5}$ implementation program, discussed below.

For upwind States affecting downwind 8-hour ozone nonattainment areas, we apply the cost factor for ozone-season NO_X controls in much the same manner as for the NO_X SIP Call, although some aspects of the analysis have been updated. The level of NO_X control identified as highly cost effective is more stringent than in the NO_X SIP Call.

d. Other Factors

As with the NO_X SIP Call, EPA considers other factors that influence the application of the air quality and cost factors, and that confirm the conclusions concerning the amounts of emissions that upwind States must eliminate as contributing significantly to downwind nonattainment. Specifically, as we stated in the CAIR NPR, ''We are striving in this proposal to set up a reasonable balance of regional and local controls to provide a cost effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone.'' (See 69 FR 4612.) In this manner, we broadly incorporate the fairness concept and relative-cost-of-control (regional costs compared to local costs) concept that we generally considered in the NO_X SIP Call.

i. $PM_{2.5}$ Controls

For $PM_{2.5}$, we promulgated the NAAQS in 1997, we issued designations of areas in December 2004 (70 FR 944; January 5, 2005), and we intend to promulgate implementation requirements during 2005. We project that by 2010, without CAIR or other controls not already adopted, 80 counties in the CAIR region would be in nonattainment of the annual standard.

Our state of knowledge is incomplete as to the best control regime to achieve attainment and maintenance of this NAAQS in individual areas, but we do know that transported SO_2 and NO_X emissions are important contributors to $PM_{2.5}$ nonattainment. In addition, we have concluded that available controls for at least the portion of these emissions from EGUs are feasible and relatively inexpensive on a cost-per-ton basis, and generate significant ambient benefits. These ambient benefits include bringing many areas into attainment and decreasing $PM_{2.5}$ levels in the rest of the nonattainment areas. Moreover, available information indicates that local controls are likely to be relatively more expensive on a per-ton basis, and will not reduce emissions sufficiently to bring many areas into attainment.

In light of this information, we plan to proceed by requiring the level of regulatory control specified today on upwind SO_2 and NO_X emissions. We consider today's action to be both prudent and effective within the circumstances of the developing $PM_{2.5}$ implementation program. This action is one of the initial steps in implementing the $PM_{2.5}$ NAAQS. States, localities, and Tribes, as well as EPA, will continue to evaluate the efficacy of local controls. Finally, as discussed in section VI, air quality modeling confirms that these regional controls are not more than is necessary for downwind areas to attain.

This overall plan is well within the ambit of EPA's authority to proceed with regulation on a step-by-step basis. The time frame for section 110(a)(2)(D) SIPs, described in section VII, makes clear that EPA has the authority to

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establish the upwind reduction obligations before having full information about how best to achieve attainment goals, including having full information about downwind control costs and the efficacy of downwind control measures.

ii. Ozone Controls

The EPA determined the level of required NO_X reductions for purposes of 8-hour ozone transport through much the same process as for purposes of $PM_{2.5}$ transport.

e. Regulatory Requirements

i. Annual SO_2 and NO_X Emissions Reductions

Although EPA determined that upwind emissions will contribute significantly to both $PM_{2.5}$ nonattainment and 8-hour ozone nonattainment in 2010, the amount of requisite emissions controls cannot feasibly be implemented by 2009 for NO_X, or 2010 for SO_2. Instead, EPA has determined to implement the reductions in two phases for each pollutant: 2009 for NO_X, and 2010 for SO_2 initially, with lower caps for both in 2015.

As described in section IV, EPA evaluated the cost of emissions reductions under consideration against the level of highly cost-effective controls. Through a multi-year process involving studies and other regulatory and legislative efforts, as well as involvement with citizen, industry, and State stakeholders, EPA arrived at an amount of SO_2 emissions reductions for evaluation purposes for the CAIR region. The EPA ascertained the costs of these reductions and today determines that they should be considered highly cost effective. These amounts correspond to reducing Title IV SO_2 allowances for utilities by 65 percent in 2015 and 50 percent in 2010 in CAIR States.

As described in section V, EPA further determined that these emissions reductions requirements should be allocated to the States in proportion to the title IV SO_2 allowances allocated under the CAA to their EGUs. This approach is consistent with the system Congress established for allocating title IV allowances and facilitates implementation of the SO_2 interstate trading program.

For annual NO_X emissions, EPA determined a target regionwide amount of both emissions reductions and the EGU budget by multiplying current heat input by emission rates of 0.125 lb/mmBtu and 0.15 lb/mmBtu for 2015 and 2010, respectively. The EPA then evaluated those amounts through the Integrated Planning Model (IPM), which indicated the associated amounts of heat input and emission rates projected for those years. The IPM indicated that the amounts of heat input for 2015 and 2010 were higher than current heat input (in light of the increased electricity demand for 2015 and 2010), and that the emissions rates were lower than 0.125 lb/mmBtu (2015) and 0.15 lb/mmBtu (2010). The IPM calculated the costs to achieve those emissions reductions and EGU budget (assuming EGU controls) by 2015 and 2009, which costs EPA determined were highly cost effective and feasible, respectively. The EPA used this same approach to determine the seasonal budget for NO_X reductions for purposes of the ozone standard.

As described in section V, we allocated this regionwide amount to the individual States in accordance with their average heat input from EGUs both subject to and not subject to title IV. We adjusted heat input for type of fuel used. The EPA believes that this method is a reasonable indicator of each State's appropriate share of the requirements. This method differs from what EPA used in the NO_X SIP Call, which relied on State-specific projections of growth in heat input.

We require implementation of the $PM_{2.5}$ and 8-hour ozone reductions in two phases, in 2009 and 2015. As discussed in section IV, these dates are the most expeditious that are practicable—the same standard for the implementation period in the NO_X SIP Call—based on engineering and financial factors; the performance and applicability of control measures; and the impact of implementation on, in the case of EGUs, electricity reliability. The EPA considered these same factors in determining the implementation period for the NO_X SIP Call requirements, but factual differences lead to the two-phase approach adopted in today's action.

As discussed in section VII, each upwind State may achieve the required reductions by regulating any sources of SO_2 or NO_X that it wishes. However, if the State chooses to regulate certain source categories (such as EGUs), it must comply with certain requirements (such as capping EGU emissions), and it may take advantage of certain opportunities (such as participation in the EPA-administered EGU cap and trade program). Some aspects of these requirements and the cap and trade program differ from those in the NO_X SIP Call, as explained in section VIII. However, like the NO_X SIP Call, the State may allow sources to opt in to the CAIR trading program, as described in section VIII.

f. SIP Submittal and Implementation Requirements

Today EPA requires that the $PM_{2.5}$ and 8-hour ozone SIPs be submitted within 18 months of promulgation of today's action. This period is 6 months longer than the SIPs due under the NO_X SIP Call. This difference is due to the fact that $PM_{2.5}$ implementation is only now beginning, and it makes sense to keep the NO_X SIPs due under the 8-hour ozone requirements on the same schedule as the NO_X and SO_2 SIPs due under the $PM_{2.5}$ requirements.

2. What Did Commenters Say and What Is EPA's Response?

Many of the comments on today's action concern various aspects of EPA's analytical approach. Most of those comments are discussed elsewhere in today's action. Comments on the most basic elements of EPA's approach are discussed here.

a. Aspects of Contribute-Significantly Test

i. Date for Evaluation of Downwind Impacts

Comment: Some commenters took issue with EPA's approach of determining the upwind State's air quality impact on downwind areas by modeling only the State's 2010 base case emissions (that is, projected 2010 emissions before the 2010 CAIR controls). These commenters stated that although evaluating the upwind State's base case emissions in 2010 might indicate whether that State's air quality impact on downwind areas is sufficiently high to justify imposition of the 2010 (Phase I) controls, it does not justify imposition of the 2015 (Phase II) controls. Rather, according to the commenters, EPA should conduct further air quality modeling that evaluates the upwind State's 2015 base case emissions—taking into account the CAIR 2010 controls but not the CAIR 2015 controls—to determine whether the State continues (even after imposition of the CAIR 2010 controls) to have a sufficient downwind ambient impact to justify the 2015 controls.

Commenters added that, in their view, $PM_{2.5}$ precursors generally were decreasing after 2010, the $PM_{2.5}$ nonattainment problem was generally diminishing as well, and the contribution of some upwind States to downwind areas was relatively small. These facts, according to the commenters, indicated that some upwind States should not be subject to the 2015 reductions requirement.

Some commenters stated, more broadly, that the threshold contribution

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level selected by EPA should be considered a floor, so that upwind States should be obliged to reduce their emissions only to the level at which their contribution to downwind nonattainment does not exceed that threshold level.

Response: The EPA views the CAIR emission reduction requirements as a single action, but one that cannot be fully implemented in 2009 (for NO_X) or 2010 (for SO_2), and must instead be partially deferred until 2015, solely for reasons of feasibility. Under these circumstances, EPA does not believe it appropriate to re-evaluate the 2015 component, as commenters have suggested.

Under EPA's approach, which mirrors that of the NO_X SIP Call, EPA projects, for each upwind State, SO_2 and NO_X inventories, as of 2010, taking into account controls required under other CAA provisions and controls adopted by State and local agencies. The EPA then uses air quality modeling techniques to determine the impact of these emissions on downwind air quality. The EPA then requires upwind States whose emissions have a sufficiently high impact to eliminate the amount of their emissions that could be eliminated through application of highly cost-effective controls. These emissions reductions must be implemented as expeditiously as practicable. Were it feasible to implement all the reductions by 2009 (for NO_X) or 2010 (for SO_2), EPA would so require. Because part of the emissions reductions cannot feasibly be implemented until 2015, EPA is requiring today's two-phase approach. This analytic method is the same as for the NO_X SIP Call, except that in that rulemaking all of the required emissions reductions could feasibly be implemented in one phase.

As in the case of the NO_X SIP Call, EPA takes the view that once a State's emissions are determined to contribute to downwind nonattainment by at least a threshold amount, then the upwind State should reduce its emissions by the amount that would result from implementation of highly cost-effective controls. This approach is justified by the benefits of reducing the upwind contribution to downwind nonattainment, coupled with the relatively low costs. However, EPA does consider the ambient impacts of the required emissions reductions. For today's action, air quality modeling indicates that the regionwide emissions reductions do not reduce $PM_{2.5}$ levels beyond what is needed for attainment and maintenance. (See also section III below.) Most important for present purposes, as long as the controls yield downwind benefits needed to reduce the extent of nonattainment, the controls should not be lessened simply because they may have the effect of reducing the upwind State's contribution to below the initial threshold.

The DC Circuit, in upholding the NO_X SIP Call, rejected similar arguments to those raised by commenters (*Michigan* v. *EPA,* 213 F.3d at 679). In the NO_X SIP Call rulemaking, commenters argued that EPA's analytic approach to the ''contribute significantly'' test was flawed because it meant that States with different impacts downwind would nevertheless have to implement the same level of controls (*i.e.*, those that were highly cost effective). Commenters urged EPA to recast its approach by limiting an upwind State's emissions reductions to the point at which the remaining emissions no longer caused a downwind ambient impact above the threshold level for significance. (''Responses to Significant Comments on the Proposed Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone (62 FR 60318; November 7, 1997 and 63 FR 25902; May 11, 1998),'' U.S. E.P.A. (September 1998), Docket Number A–96–56–VI–C–1, at 213–16.)

Petitioners challenging the NO_X SIP Call in *Michigan* v. *EPA* used the same arguments to contend that EPA's analytic approach in the NO_X SIP Call was arbitrary and capricious. The Court dismissed these arguments, stating:

> * * * EPA required that all of the covered jurisdictions, regardless of amount of contribution, reduce their NO_X by an amount achievable with ''highly cost-effective controls.'' Petitioners claim that EPA's uniform control strategy is irrational. * * * [T]hey observe that where two states differ considerably in the amount of their respective NO_X contributions to downwind nonattainment, under the EPA rule even the small contributors must make reductions equivalent to those achievable by highly cost-effective measures. This of course flows ineluctably from the EPA's decision to draw the ''significant contribution'' line on a basis of cost differentials. Our upholding of that decision logically entails upholding this consequence.

(*Michigan* v. *EPA,* 213 F.3d at 679.)

Thus, the Court approved EPA's approach of requiring the same control level on all affected States, without concern as to the arguably inconsistent ambient impacts that may result. By the same token, in today's action, EPA's approach should be accepted notwithstanding that the upwind controls could, at least in theory, result in an ambient impact that is below the initial threshold. For this reason, there is no basis to conduct a separate evaluation of the 2015 controls.

ii. Residual Nonattainment

Comment: A commenter expressed concern that too many areas will remain out of attainment for the $PM_{2.5}$ and 8-hour ozone NAAQS even after implementation of the CAIR rule.

Response: Section 110(a)(2)(D) of the CAA requires upwind States to prohibit the amount of emissions that contribute significantly to downwind nonattainment, but does not require the upwind States to prohibit sufficient emissions to assure that the downwind areas attain. Rather, downwind areas continue to bear the responsibility of addressing remaining nonattainment.

iii. Relationship of Reductions to Attainment Dates

Comment: Some commenters, who viewed the CAIR as imposing unduly light obligations on upwind States, argued that because States with nonattainment areas must develop SIPs that provide for attainment regardless of the cost of the requisite controls, and because the courts have viewed attainment deadlines as central to the CAA, EPA should require that upwind emissions contributing to downwind nonattainment must be eliminated by the downwind attainment dates, and not later.

Other commenters, who viewed the CAIR as imposing unduly heavy obligations on upwind States, argued that EPA had no authority to require upwind emissions reductions after the downwind attainment dates because by that time, the upwind emissions were no longer contributing to nonattainment. These commenters further argued that EPA has no authority to accelerate the emissions reductions because the controls could not feasibly be implemented by an earlier date.

Response: We note first that part of this issue is moot since EPA is requiring NO_X controls in 2009, within the statutory time periods for attainment. With respect to remaining issues, EPA's interpretation and application of the ''contribute significantly to nonattainment'' standard of section 110(a)(2)(D) is not necessarily constrained by the downwind area's attainment date in either manner suggested by the commenters.

First, although it is true that the nonattainment area requirements and deadlines in CAA title I, part D, mean that the downwind area must achieve attainment by its attainment date

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without regard to the feasibility of emissions reductions from sources in that nonattainment area, section 110(a)(2)(D) by its terms does not apply those constraints to sources in the upwind States. Rather, EPA's interpretation of the ''contribute significantly to nonattainment'' standard—which incorporates feasibility considerations in determining the implementation period for the upwind emissions controls—continues to apply.

Often, upwind emissions reductions affect at least several downwind areas with different attainment dates. The EPA does not read section 110(a)(2)(D) to require that the pace of upwind reductions be controlled by the earliest downwind attainment date. Rather, EPA views the pace of reductions as being determined by the time within which they may feasibly be achieved. In some cases, upwind sources are themselves in a nonattainment area that has a longer attainment date than the downwind area, and it may not be feasible for those upwind sources to implement reductions prior to the downwind attainment date. Therefore, the upwind emissions may be projected to continue to affect adversely nonattainment in the downwind area even after the downwind attainment date, in the manner described above. Further, emissions reductions after the attainment date may be important to prevent interference with maintenance of the standards.

The CAIR will achieve substantial reductions in time to help many nonattainment areas attain the standards by the applicable attainment dates. The design of the SO_2 program, including the declining caps in 2010 and 2015 and the banking provisions, will steadily reduce SO_2 emissions over time, achieving reductions in advance of the cap dates; and the 2009 and 2015 NO_X reductions will be timely for many downwind nonattainment areas. Although many of today's nonattainment areas will attain before all the reductions required by CAIR will be achieved, it is clear that CAIR's reductions will still be needed through 2015 and beyond. The EPA has determined that each upwind State's 2010 and 2015 emissions reductions will be necessary because, for purposes of both $PM_{2.5}$ and 8-hour ozone, we reasonably predict that a downwind receptor linked to that upwind State will either: (i) Remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind State's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory. This is discussed in detail in section III below.

iv. Factors To Consider in Future Rulemaking

In the January and June CAIR proposals, we discussed regional control requirements and budgets based on a showing of ''significant contribution'' by upwind States to nonattainment in downwind States (69 FR at 4611–13, 32720). The CAA section 110(a)(2)(D), which provides the authority for CAIR, states among other things that SIPs must contain adequate provisions prohibiting, consistent with the CAA, sources or other types of emissions activity within a State from emitting pollutants in amounts that will ''contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to'' the NAAQS. In the CAIR, EPA has interpreted section 110(a)(2)(D) to require that certain States reduce emissions by specified amounts, and has determined those amounts based on the availability of highly cost effective controls for identified source categories. Following this interpretation, EPA has calculated CAIR's emissions reduction requirements based on the availability of highly cost-effective reductions of SO_2 and NO_X from EGUs in States that meet EPA's proposed inclusion criteria.

One approach cited in the January 2004 CAIR proposal for ensuring that both the air quality component and the cost effectiveness component of the section 110 ''contribute significantly'' determination is met, is to consider a source category's contribution to ambient concentrations above the attainment level in all nonattainment areas in affected downwind states. *Id.* In the June supplemental proposal, we requested comment on a further refinement of this concept—*i.e.*, whether a source category should be included in a broad regional rule promulgated pursuant to section 110(a)(2)(D) only if the proposed level of additional control of that category would meet a specified threshold. Under that approach, EPA said it might determine, for example, that in the context of a broad multi-state SIP call, emissions reductions from particular source category are ''highly cost effective'' only if emissions reductions from that source category would result in at least 0.5 percent of U.S. counties and/or parishes coming into attainment with a NAAQS. The EPA noted that, given the number of counties and parishes in the United States, this requirement would be met if at least 16 counties were brought into attainment with a NAAQS as a result of the proposed level of control on a particular source category.

The Agency received comments both supporting and opposing the adoption of this test as a part of the ''highly cost effective'' component of the ''contribute significantly'' requirement of CAA section 110(a)(2)(d). Commenters supporting this test asserted that it was consistent with the CAA's overall focus on State, rather than federal, control over which sources should be regulated, and also was consistent with ensuring that broad, regional SIP calls, such as the one at issue in this case, focus only on source categories the control of which will result in substantial overall improvements in air quality. Commenters opposing this screen with respect to the application of section 110(a)(2)(D) asserted, in general, that the test would be inconsistent with the analysis used by the Agency in the NO_X SIP call and with the language of section 110(a)(2)(D).

We have determined that it is not appropriate to adopt a statutory interpretation embodying a ''bright line'' rule that 0.5 percent of the U.S. counties and/or parishes must be brought from nonattainment into attainment from controlling emissions from a particular source category, in order for reductions from that source category to be considered highly cost effective. We continue to believe, however, that broad multi-state rules under section 110(a)(2)(D), such as the one we are finalizing today, should play a limited role under the CAA and must be justified by a careful evaluation of the air quality improvement that will result from the controls under consideration. Therefore, we intend to undertake any future broad, multi-state rulemakings under section 110(a)(2)(D) regarding transported emissions only when, as here, they produce substantial air quality benefits across a broad area and have beneficial air quality impacts on a significant number of downwind nonattainment areas, including bringing many areas into attainment. We do not at this time anticipate the need for any such rulemakings in the future. We believe that today's action, coupled with current and upcoming national rules and local or subregional programs adopted by States, will be sufficient to address the remaining nonattainment problems.

In evaluating whether to undertake national or regional transport rulemakings in the future, we believe it is not only appropriate but necessary to consider the effectiveness of the proposed emissions reductions in improving downwind air quality. We

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believe it will be reasonable to initiate a broad multi-state rulemaking under section 110(a)(2)(D) based on a determination that particular emissions reductions are highly cost effective only when those reductions will bring a significant number of downwind areas into attainment. In adopting this approach for determining whether a future broad, multi-state SIP call is appropriate, we note that other CAA mechanisms, such as SIP disapproval authority and State petitions under section 126, are available to address more isolated instances of the interstate transport of pollutants.

The EPA projects that control of SO_2 and NO_X through CAIR will bring 72 counties into attainment with the $PM_{2.5}$ and ozone NAAQS. The total number represents approximately 3 percent of the counties/parishes in the United States, and is clearly a significant number of areas. What will be considered a significant number of areas in any future cases will need to be determined on a case-by-case basis.

III. Why Does This Rule Focus on SO_2 and NO_X, and How Were Significant Downwind Impacts Determined?

This section discusses the basis for EPA's decision to require reductions in upwind emissions of SO_2 and NO_X to address $PM_{2.5}$ transport and to require reductions in upwind emissions of NO_X to address ozone-related transport. In addition, this section discusses how EPA determined which States are subject to today's rule because their sources' emissions will significantly contribute to nonattainment of the $PM_{2.5}$ or 8-hour ozone standards, or interfere with maintenance of those standards, in downwind States. The EPA assessed individual upwind States' ambient impacts on downwind States and established a threshold value to identify those States whose impact constitutes a significant contribution to air quality violations in the downwind States. The EPA used air quality modeling of emissions in each State to estimate the ambient impacts. The technical issues concerning the modeling platform and approach are discussed in section VI, Air Quality Modeling Approach and Results. Also, EPA considered the potential for upwind state emissions to interfere with maintenance of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind areas.

A. What Is the Basis for EPA's Decision To Require Reductions in Upwind Emissions of SO_2 and NO_X To Address $PM_{2.5}$ Related Transport?

1. How Did EPA Determine Which Pollutants Were Necessary To Control To Address Interstate Transport for $PM_{2.5}$?

a. What Did EPA Propose Regarding This Issue in the NPR?

Section II of the January 2004 proposal summarized key scientific and technical aspects of the occurrence, formation, and origins of $PM_{2.5}$, as well as findings and observations relevant to formulating control approaches for reducing the contribution of transport to fine particle problems (69 FR 4575–87). Key concepts and provisional conclusions drawn from this discussion can be summarized as follows: [17]

(1) Fine particles (measured as $PM_{2.5}$ for the NAAQS) consist of a diverse mixture of substances that vary in size, chemical composition, and source. The $PM_{2.5}$ includes both ''primary'' particles that are emitted directly to the atmosphere as particles, and ''secondary'' particles that form in the atmosphere through chemical reactions from gaseous precursors. The major components of fine particles in the Eastern U.S. can be grouped into five categories: carbonaceous material (including both primary and secondary organic carbon and black carbon), sulfates, nitrates, ammonium, and crustal material, which includes suspended dust as well as some other directly emitted materials. The major gaseous precursors of $PM_{2.5}$ include SO_2, NO_X, ammonia (NH_3), and certain volatile organic compounds.

(2) Examination of urban and rural monitors indicate that in the Eastern U.S., sulfates, carbonaceous material, nitrates, and ammonium associated with sulfates and nitrates are typically the largest components of transported $PM_{2.5}$, while crustal material tends to be only a small fraction.

(3) Atmospheric interactions among particulate ammonium sulfates and nitrates and gas phase nitric acid and ammonia vary with temperature, humidity, and location. Both ambient observations and modeling simulations suggest that regional SO_2 reductions are effective at reducing sulfate and associated ammonium, and, therefore, $PM_{2.5}$. Under certain conditions reductions in particulate ammonium sulfates can release ammonia as a gas, which then reacts with gaseous nitric acid to form nitrate particles, a phenomenon called ''nitrate replacement.'' In such conditions SO_2 reductions would be less effective in reducing $PM_{2.5}$, unless accompanied by reductions in NO_X emissions to address the potential increase in nitrates.

(4) Reductions in ammonia can reduce the ammonium, but not the sulfate portion of sulfate particles. The relative efficacy of reducing nitrates through NO_X or ammonia control varies with atmospheric conditions; the highest particulate nitrate concentrations in the East tend to occur in cooler months and regions. At present, our knowledge about sources, emissions, control approaches, and costs is greater for NO_X than for ammonia. Existing programs to reduce NO_X from stationary and mobile sources are well underway. From a chemical perspective, as NO_X reductions accumulate relative to ammonia, the atmospheric chemical system would move towards an equilibrium in which ammonium nitrate reductions become more responsive to further NO_X reductions relative to ammonia reductions.

(5) Much less is known about the sources of regional transport of carbonaceous material. Key uncertainties include how much of this material is due to biogenic as compared to anthropogenic sources, and how much is directly emitted as compared to formed in the atmosphere.

(6) Observational evidence suggests that the substantial reductions in SO_2 emissions in the eastern U.S. since 1990 have indeed caused observed reductions in $PM_{2.5}$ sulfate. The relatively small historical reductions in NO_X emissions do not allow observations to be used similarly to test the effectiveness of NO_X reductions.

Based on the understanding of current scientific and technical information, as well as EPA's air quality modeling, as summarized in the January 30 proposal, EPA concluded that it was both appropriate and necessary to focus on control of SO_2 and NO_X emissions as the most effective approach to reducing the contribution of interstate transport to $PM_{2.5}$.

The EPA proposed not to control emissions that affect other components of $PM_{2.5}$, noting that ''current information relating to sources and controls for other components identified

[17] More complete discussions of the key scientific underpinnings that form the basis of these conclusions in the proposal and the discussion of these issues in this seciton of today's notice can be found in the recently completed EPA Criteria Document (USEPA, National Center for Environmental Assessment, Air Quality Criteria for Particulate Matter, October 2004) and the NARTSO assessment of fine participles (NARSTO, Particulate Matter Science for Policy Makers—A NARSTO ASSESSMENT, February 2003).

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in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components.'' (69 FR 4582). For all of these components, the lack of knowledge of and ability to quantify accurately the interstate transport of these components limited EPA's ability to include these components in this rule.

b. How Does EPA Address Public Comments on Its Proposal To Address SO_2 and NO_X Emissions and Not Other Pollutants?

i. Overview of Comments on This Issue

A large number of commenters including states, affected industries, environmental groups, academics, and other members of the public agreed with EPA's proposal to require cost-effective multipollutant reductions of SO_2 and NO_X to address interstate transport contributions to $PM_{2.5}$ problems. Fewer commenters who supported controlling SO_2 and NO_X commented on inclusion of additional pollutants, but several also agreed that it would be premature at this time to require control of emissions of other chemical components and precursors to address such transport. These commenters suggested that SO_2 and NO_X emissions from EGUs and other sources indeed contribute significantly to downwind $PM_{2.5}$. They argued that control of other components is premature because of a lack of knowledge, either about the interstate contributions of other components or of control measures for these components. Generally, EPA accepts and agrees with these conclusions.

A number of commenters disagreed to varying degrees with part or all of EPA's proposed focus on SO_2 and NO_X. The main points raised by these commenters can be grouped as follows:

(1) The focus on SO_2 and NO_X is not appropriate because sulfates and nitrates may not be (or are not) the most important determinants of the health effects of $PM_{2.5}$.

(2) The EPA should mandate, or at least permit, states to control other precursors and particle emissions in addition to, or instead of, SO_2 and NO_X. Commenters sometimes made specific recommendations with respect to additional pollutants, including carbonaceous (including organic) particles and precursors, ammonia, and other direct emissions, including crustal material.

(3) The focus on SO_2 may be appropriate, but the basis for requiring NO_X control is not clear.

ii. Summary of EPA's Response to the Major Comments on This Issue

The following subsections summarize both key comments and EPA's responses organized by the major categories outlined above. As noted in Section I, EPA has developed and placed in the rulemaking docket a detailed response to these and other public comments.

(a) SO_2 and NO_X May Be Less Important to Health Than Other Transport-Related Components

Comment: Several commenters argued that the proposed focus on SO_2 and NO_X was premature, citing the potential for differential toxicity of various $PM_{2.5}$ components, and in some cases advancing evidence (*e.g.,* the Electric Power Research Institute Aerosol Research and Inhalation Studies [ARIES]) [18] that other components such as organic particles appear to be more responsible for health effects of particles than sulfates and nitrates. Several argued that the relative contribution of components to health impacts is an important uncertainty that should be researched more carefully before proposing to control only SO_2 and NO_X.

Response: Today's rulemaking establishes requirements for SIP submissions under section 110(a)(2)(D). Those SIP submissions must prohibit emissions that contribute significantly to nonattainment of a NAAQS in a downwind State. The EPA determined in the 1997 rulemaking promulgating the $PM_{2.5}$ NAAQS that specified levels of $PM_{2.5}$ adversely affect human health, and that sulfates and nitrates are components of $PM_{2.5}$ (62 FR 38652, July 18, 1997). SO_2 and NO_X, in turn, are precursors to fine particulate sulfates and nitrates. Comments that sulfates and nitrates do not cause adverse health effects are more appropriately raised in the context of past or ongoing reviews of the PM NAAQS. Because today's action forms part of implementing and not establishing the PM NAAQS, comments relating to the evidence supporting or not supporting health effects of all or portions of pollutants regulated by the $PM_{2.5}$ NAAQS are not germane to this rulemaking.

Nevertheless, we discuss briefly EPA's current response regarding the contributions of different components of $PM_{2.5}$ to health effects. In establishing the current $PM_{2.5}$ NAAQS, EPA found that there was ample evidence to associate various health effects with the measured mass concentration of particles smaller than a nominal 2.5 micrometers (um), termed $PM_{2.5}$. The EPA recognizes that the toxicity of different chemical components of $PM_{2.5}$ may vary, and that the observed effects may be the result of the mixture of particles and gases. While research is underway to better identify whether some chemical components are more responsible for health effects than others, results now available from such research are limited and inconclusive. A number of studies included in the recent EPA PM criteria document [19] have found effects to be associated with one or more of the major components and sources of $PM_{2.5}$, including sulfates, nitrates, organic materials, $PM_{2.5}$ mass, coal combustion, and mobile sources. The criteria document concludes that these studies suggest that many different chemical components of fine particles and a variety of different types of source categories are all linked to premature mortality and other serious health effects, either independently or in combinations, but that it is not possible to reach clear conclusions about differential effects of PM components. Accordingly, individual studies or groups of studies such as ARIES cannot be used to single out any particular component of $PM_{2.5}$ as wholly responsible (or not at all responsible) for the array of health effects that have been found to be associated with various chemical and mass indicators of fine particles. Other Federal agencies and EPA continue to promote and support the epidemiological and toxicological studies needed to better understand the effects of different chemical components and different size particles on health effects.

In the meantime, EPA believes that, given the substantial evidence of significant health effects of fine particles, it is important to move forward expeditiously to address both transported and local sources of all the major components of fine particles in an effort to implement and attain the $PM_{2.5}$ standards. Today's rule is focused on the contribution of interstate transport of nitrate and sulfates to $PM_{2.5}$ in nonattainment areas. However, EPA has already adopted other rules that are reducing emissions and exposures to these and other major components of fine particles on a national, regional, and local basis. Recent national mobile

[18] R. J. Klemm, *et al.,* ''Daily Mortality and Air Pollution in Atlanta: Two Year of Data from ARIES'' (accepted, Inhalation Toxicology).

[19] USEPA, National Center for Environmental Assessment, Air Quality Criteria for Particulate Matter, October 2004.

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rules and programs, in particular, have focused on carbonaceous materials emitted from gasoline and both highway and non-road diesel powered mobile sources (65 FR 6698; 66 FR 5002; 69 FR 38958). States with nonattainment areas will also be required to address local sources of $PM_{2.5}$ in order to meet progress and attainment requirements. Together, the collective effect of these programs ensures a balanced approach to reducing all of the major components of $PM_{2.5}$ from transported and local sources.

(b) Inclusion of Other $PM_{2.5}$ Precursors and Components

Comment: A number of commenters recommended that EPA either mandate or at least permit controls on the emissions that cause interstate transport of other components of $PM_{2.5}$, in addition to or as a substitute for, SO_2 and NO_X controls. Several commenters recommended that EPA include emissions reductions related to the components of $PM_{2.5}$ other than sulfate and nitrate. While many commenters suggested addressing all of the important contributors to $PM_{2.5}$, including those not regulated under this Rule, others highlighted only one or two additional components as most important to include. Of the $PM_{2.5}$ components, direct emissions and precursors to carbonaceous $PM_{2.5}$ and ammonia emissions were the omitted contributors most frequently discussed.

Some of these commenters argued that, by limiting the rule to SO_2 and NO_X and excluding other sources of ambient $PM_{2.5}$, EPA would be limiting the choices that states have to address their downwind interstate transport contributions. These commenters argued that this limitation is contrary to the CAA, which generally gives states the discretion to choose their own emission control strategies. Commenters further asserted that the roles of other components in $PM_{2.5}$ are sufficiently well understood that they should be included in state SIPs for $PM_{2.5}$ transport, and could partially satisfy the $PM_{2.5}$ reductions anticipated by this rule.

Response: The three main classes of $PM_{2.5}$ precursors that are not included in this rulemaking are carbonaceous material (including both primary emissions and VOC emissions that form secondary organic aerosol), ammonia, and crustal material. As noted in the proposal(69 FR 4576) and as mentioned in several comments, these components comprise a measurable faction of $PM_{2.5}$ throughout the Eastern U.S., and the contribution of carbonaceous material, in particular, is often substantial. In addition, emissions contributing to these components in one state likely do affect $PM_{2.5}$ concentrations in other states to some extent. However, the extent of those downwind contributions to nonattainment has not been quantified adequately and current scientific understanding makes such a determination more uncertain than is the case for SO_2 and NO_X. Responses to recommendations for including each of these three classes in the transport rule are summarized below.

(i)Carbonaceous Material For

carbonaceous material, uncertainties in both the quantity and origins of emissions contributing to both primary and secondary carbonaceous material on regional scales (including emissions from fires and from biogenic sources) limit the quality of regional scale modeling of carbonaceous $PM_{2.5}$. This in turn causes substantial uncertainties in determining the amount of interstate transport from carbonaceous material and of the costs and effectiveness of emission controls. Modeling and monitoring the relative amount of organic particles that come from the formation of secondary organic particles, versus primary organic particles, is also highly uncertain.

In addition, comparison of urban and nearby rural PM composition monitors [20] in the eastern U.S. find a significantly larger amount of carbonaceous materials in urban areas as compared to rural areas, suggesting that a substantial fraction of carbonaceous particles in urban areas come from local sources. By contrast, urban and non-urban monitors in the East show greater homogeneity for regional sulfate concentrations as compared to carbonaceous materials, suggesting regional sources are most important for sulfates. Results for nitrates suggest both a mixture of regional and local sources. Furthermore, as noted above and in the proposal (69 FR 4577–78), while the relative contributions of different sources to regional sulfate and nitrates can be quantified with certainty, the contributions of different sources to carbonaceous materials on a regional scale are less clear. Moreover, as noted in the NPR preamble, some research into mechanisms of formation of organic particles suggests that both NO_X and SO_2 reductions might be of some benefit in lowering the amount of secondary organic particles.[21] Current models are not, however, capable of quantifying such potential benefits.

While EPA does not believe that enough is known about the relative effectiveness or costs of reducing anthropogenic sources of carbonaceous particles on transported $PM_{2.5}$, EPA agrees that control of known source categories of these materials can have a significant benefit in reducing the significant local contribution. For this reason, EPA has already enacted other national rules that will reduce emissions of primary carbonaceous $PM_{2.5}$ from mobile sources, the largest contributor to such emissions. In addition to reducing $PM_{2.5}$ in nonattainment areas, these regulations will also have the benefit of reducing a large measure of whatever interstate transport of carbonaceous $PM_{2.5}$ occurs.

(ii) Ammonia

While current models are able to address the major chemical mechanisms involving particulate ammonium compounds, regional-scale ammonia emissions, particularly from agricultural sources, are highly uncertain.[22] Given the relative lack of experience in controlling such sources, the costs and effectiveness of actions to reduce regional ammonia emissions are not adequately quantified at present. As noted above, ammonium would not exist in $PM_{2.5}$ if not for the presence of sulfuric acid or nitric acid; hence, decreases in SO_2 and NO_X can be expected ultimately to decrease the ammonium in $PM_{2.5}$ as well. The additional regional limits on SO_2 and NO_X emissions outlined in today's notice added to those reductions provided under current programs would likewise be expected to reduce the $PM_{2.5}$ effectiveness of any ammonia control initiative.[23] Unlike ammonium, sulfuric acid has a very low vapor pressure and would exist in the particle with or without ammonia. Therefore, while SO_2 reductions would reduce particulate ammonium, changes in ammonia would

[20] V. Rao, N. Frank, A. Rush, F. Dimmick. Chemical Speciation of $PM_{2.5}$ in Urban and Rural Area, in The Proceedings of the Air & Waste Management Association Symposium on Air Quality Measurement Methods and Technology, San Francisco, November 13–1, 2002.

[21] Jang, M; Czoschke, N.M.; Lee, S.: Kamens, R.M., Heterogeneous Atmospheric Aerosol Production by Acid-Catalzyed Particle Phase Reactions, Science, 2002, 298: 814–817.

[22] Battye, W., V.P. Aneja, and P.A. Roelle, Evaluation and improvement of ammonia emissions inventories, Atmospheric Environment, 2003, 37: 3873–3883.

[23] As pointed out by one commenter, a hypothetical new program resulting in major regional reductions of ammonia would reduce the effectiveness of NO_X controls. However, given the uncertainties in emissions, the dispersed nature of ammonia sources and the lack of present controls, an effort to develop a new regional ammonia program would likely take significantly longer than the additional NO_X reductions EPA is adopting today.

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be expected to have very little effect on the sulfate concentration.

In addition to the above considerations, because ammonium nitrates are highest in the winter, when ammonia emissions are lowest, reducing wintertime NO_X emissions may represent a more certain path towards reducing this winter peak than ammonia reductions. Moreover, reductions in ammonia emissions alone would also tend to increase the acidity of $PM_{2.5}$ and of precipitation. As noted in the proposal, this might have untoward environmental or health consequences.

Some commenters highlighted ammonia as an important pollutant with multiple effects on the environment, including its contributions to $PM_{2.5}$. These commenters highlighted that ammonia emissions are not currently regulated extensively, and suggested that EPA strengthen its efforts to better understand the many effects of ammonia emissions and better research options for controlling ammonia, so that it can be regulated where appropriate in the future programs. Generally, EPA agrees with these commenters.

(iii) Crustal Material

The contributions of crustal materials to $PM_{2.5}$ nonattainment are usually small, and the interstate transport of crustal materials is even smaller. Emissions of crustal materials on regional scales are uncertain, highly variable in space and time, and may not be easily controlled in some cases, suggesting significant uncertainties in quantifying emissions and the costs and effectiveness of control actions. Emissions reductions of SO_2 and NO_X will likely reduce some of the direct emissions of $PM_{2.5}$ from EGUs and other industries, which are responsible for a portion of the ''crustal material'' measured downwind at receptors.

(c) Summary of Response To Requiring or Allowing Reductions in Other Pollutants

After reviewing public comments in light of the current understanding of alternative pollutants as summarized above, EPA disagrees with those commenters who suggested that the final Clean Air Interstate Rule should require states to address the interstate transport of carbonaceous material (including VOCs), ammonia, and/or crustal material in the present rulemaking.

At present, the sources and emissions contributing to these components on regional scales are not sufficiently quantified. In addition, the representation of atmospheric physics and chemistry for these components in air quality models is in some cases poor in comparison with current understanding of SO_2 and NO_X (most notably for sources and amounts of secondary organic aerosol production.[24] Consequently, quantification of the interstate transport of these components is significantly more uncertain than for SO_2 and NO_X emissions. Given these uncertainties in regional emissions and interstate transport of these components, EPA has determined that it would be premature to quantify interstate impacts of these emissions through zero-out modeling, as was done for SO_2 and NO_X emissions.

In addition, the costs of control measures, their effectiveness at reducing emissions, as well as their ultimate effectiveness at reducing $PM_{2.5}$ concentrations at downwind receptors are all uncertain. The EPA does not believe it could reasonably evaluate whether such State emissions contributed significantly to transport, or what level of control would address the significant contribution. Commenters have not provided us specific data and information to allow such assessments.

The EPA also disagrees with commenters who argue that EPA should, for the purposes of this rule, permit the States to substitute controls of sources of any of these other three components for the required limits on SO_2 and NO_X. Given the greater uncertainties in estimating the contribution of alternative source emissions, States would have difficulty developing, and EPA would have difficulty in approving, SIPs that, by controlling these components, purport to reduce an upwind State's impact on downwind $PM_{2.5}$ nonattainment by an equivalent amount to that required in today's final rule.

As explained in the proposal, a decision not to regulate these components of $PM_{2.5}$ in the present rulemaking does not preclude state or local $PM_{2.5}$ implementation plans from reducing emissions of carbonaceous material, ammonia, or crustal material, in order to achieve attainment with $PM_{2.5}$ standards, in cases where there is evidence that such controls will be effective on a local basis. Although uncertainties exist in addressing long-range transport of these pollutants, state and local air quality management agencies will need to evaluate reasonable control measures for sources of these pollutants in developing SIPs due in 2008. We expect continuous improvements will be made in our understanding of source emissions and $PM_{2.5}$ components not addressed under CAIR. To assist future air quality management decisions, EPA is actively supporting research into better understanding the emissions, atmospheric processes, long range transport, and opportunities for control of these $PM_{2.5}$ components.

(d) Justification for Including NO_X in Determining Significant Contributions and for Regulating NO_X Emissions for $PM_{2.5}$ Transport

Some commenters questioned the EPA's basis for requiring emissions reductions of NO_X, in addition to SO_2, for the purposes of controlling interstate transport of $PM_{2.5}$. These comments, and EPA's response, are discussed below. Other comments addressing EPA's basis for requiring NO_X for ozone are addressed in a subsequent section.

Like SO_2, NO_X emissions are understood to affect $PM_{2.5}$ on regional scales, due in part to the time needed to convert NO_X emissions to nitrate. Like SO_2 but unlike precursors of other components of $PM_{2.5}$, emissions of NO_X are well quantified for EGUs and with reasonable accuracy for other urban and regional sources, and the transport of NO_X and $PM_{2.5}$ derived from NO_X can also be quantified with a fair degree of certainty. In addition, SO_2 and NO_X interact as part of the same chemical system in the atmosphere. Controlling SO_2 emissions without concurrently controlling NO_X emissions can lead to nitrate replacement whereby SO_2 emissions reductions will be less effective than expected. Finally, SO_2 and NO_X share common sources in fossil fuel combustion. As such, controlling emissions of both precursors in a coordinated way presents opportunities to reduce the overall cost of the control program.[25]

Commenters questioned EPA's methodology of evaluating whether an upwind State contributes significantly to $PM_{2.5}$ nonattainment by considering (through the ''zero-out'' air quality modeling technique) SO_2 and NO_X emissions simultaneously. These commenters argued that zeroing out SO_2 and NO_X emissions simultaneously precludes determining the contribution of each component to downwind nonattainment. Because sulfates generally comprise a greater fraction of $PM_{2.5}$ than nitrates in the Eastern U.S., these commenters argued that the basis for requiring NO_X controls is weaker than for SO_2, and has not been determined directly by EPA.

[24] EPA OAQPS CMAQ Evaluation for 2001 Docket # OAR–2003–0053–1716.

[25] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

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The EPA's multi-pollutant approach of modeling SO_2 and NO_X contributions at the same time is consistent both with sound science and with the requirements of CAA section 110(a)(2)(D), as EPA interpreted and applied them in the NO_X SIP Call. This provision requires each State to submit a SIP to prohibit ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will * * * contribute significantly to nonattainment'' downwind. As discussed in section II above, in the NO_X SIP Call, a rulemaking in which EPA regulated NO_X emissions as precursors for ozone, EPA found that ozone resulted from the combined contributions of many emitters over a multistate region, a phenomenon that EPA termed ''collective contribution'' (63 FR 57356–86). As a result, EPA evaluated each State's contribution to nonattainment downwind by considering the impact of the entirety of that State's NO_X emissions on downwind nonattainment. Once EPA determined the State's entire NO_X emissions inventory to have at least a minimum downwind impact, then EPA required the State to eliminate the portion of those emissions that could be reduced through highly cost-effective controls. The EPA considered this approach to be consistent with the section 110(a)(2)(D) requirements.

In a companion rulemaking, the section 126 Rule, EPA found that certain, individual NO_X emitters must be subject to Federal regulation due to their impact on downwind nonattainment (65 FR 2674). The EPA based this finding on the same notion of ''collective contribution,'' that is, NO_X emissions from those individual sources were part of the upwind State's total NO_X inventory, the total NO_X inventory had a sufficiently high impact on downwind nonattainment, and therefore the individual NO_X emitters should be subject to control without any separate determination as to their individual impacts on downwind nonattainment.

The DC Circuit accepted EPA's collective contribution approach upholding most of the NO_X SIP Call regulation, in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), *cert. denied* 532 U.S. 904 (2001). Similarly, the DC Circuit upheld most aspects of EPA's Section 126 Rule, including the collective contribution basis for finding that emissions from the individual sources should be subject to regulation. *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032 (DC Cir. 2001) (per curium).

As discussed elsewhere, $PM_{2.5}$ is similar to ozone in that it is the result of emissions from many sources over a multi-state region. Accordingly, EPA considers that the phenomenon of ''collective contribution'' is associated with $PM_{2.5}$ as well.

In the CAIR NPR, EPA selected SO_2 and NO_X as the appropriate precursors to be controlled for $PM_{2.5}$ transport, for several reasons presented above. As in the NO_X SIP Call, today's rulemaking, under CAA section 110(a)(2)(D), requires EPA to evaluate whether a particular upwind State must submit a SIP that prohibits ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will * * * contribute significantly to nonattainment'' downwind. In making this determination, EPA considers the effects of all of the appropriate precursors—here, both SO_2 and NO_X—from all of the State's sources on downwind $PM_{2.5}$ nonattainment. If that collective contribution to downwind $PM_{2.5}$ nonattainment is sufficiently high, then EPA requires the upwind State to eliminate those precursors to the extent of the availability of highly cost-effective controls.

The EPA's approach to evaluating a State's impact on downwind nonattainment by considering the entirety of the State's SO_2 and NO_X emissions is also consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to the nitrate replacement phenomenon, as well as other complex chemical reactions that can include organic compounds as well. As commenters point out, the nature of these reactions can vary with location and time. The non-linear nature of some of these reactions can produce differing results depending on the relative amount of reductions and copollutants. Reductions in sulfates can increase nitrates and, in some conditions, modest reductions in nitrates can increase sulfates although through different mechanisms. Large regional reductions in both pollutants, however, are more likely to result in a significant reductions in fine particles.[26]

Based on its current understanding of regional air pollution and modeling results, EPA believes that adopting a broad new program of regional controls to continue the downward trajectory in both SO_X and NO_X begun in base programs such as the national mobile source rules and Title IV, as well as the NO_X SIP call, will ultimately result in significant benefits not only in reducing $PM_{2.5}$ nonattainment, but improving public health, reducing regional haze, and addressing multimedia environmental concerns including acid deposition and nutrient loadings in sensitive coastal estuaries in the East.[27]

Some commenters argued that the benefits of combining NO_X with SO_2 reductions, if any, would be small, and further argued that the effect of any nitrate reductions in the environment would be further diminished by measurement losses that can occur in the filter in the method used to measure $PM_{2.5}$. In so doing, they questioned the scientific basis for nitrate replacement, suggesting that this response to changes in SO_2 emissions may not happen in all places and at all times. The commenters referenced a study in the Southeastern U.S. by Blanchard and Hidy,[28] which they claim calls into question whether nitrate replacement actually occurs. In fact, the study finds evidence that nitrate replacement occurs: ''the sulfate decreases were an input to the model calculations, but their effect on fine PM mass was modified by concomitant decreases in ammonium and increases in nitrate.'' A second study by the same authors, using essentially the same dataset and methods, and referenced both by EPA in the NPR and by the commenters, gives very strong support for the existence of nitrate replacement, as well as for coordinating SO_2 and NO_X reductions, as indicated by the following conclusions: ''reductions in sulfate through SO_2 reduction at constant NO_X levels would not result in proportional reduction in $PM_{2.5}$ mass because particulate nitrate concentrations would increase. However, if both NO_X and SO_2 emissions are reduced, then it may be possible to achieve sulfate reductions without concomitant nitrate increases * * *'' [29]

Nitrate replacement is well documented in the scientific literature as a possible response of $PM_{2.5}$ to changes in SO_2 emissions.[30] While these commenters are correct that nitrate replacement is not expected to occur at all places and at all times, even where average conditions are not favorable for

[26] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

[27] ''Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005).''

[28] Blanchard, C.L., and G.M. Hidy (2004) Effects of projected utility SO_2 and NO_X emission reductions on particulate nitrate and $PM_{2.5}$ mass concentrations in the Southeastern United States, Report to Southern Company. See CAIR docket.

[29] Blanchard C.L., and G.M. Hidy (2003). Effects of changes in sulfate, ammonia, and nitric acid on particulate nitrate concentrations in the Southeastern United States, J. Air & Waste Manage. Assoc., 53: 283–290.

[30] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

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nitrate replacement, hourly variability in those conditions can create conditions favorable for nitrate replacement at particular times. Nitrate replacement theory predicts no conditions under which SO_2 reductions would decrease nitrate, and suggests that nitrate may increase under fairly common conditions.[31] Consequently, the net effect of SO_2 reductions can be only to increase nitrate or not to have any effect. The variability of conditions occurring over a year means that SO_2 reductions would be expected to increase nitrate on balance.

Even if the studies referenced by these commenters showed that nitrate replacement does not occur in some circumstances, other studies suggest that the conditions for nitrate replacement are common in the Eastern U.S.[32] Suggesting that nitrate replacement does not occur under some conditions does not imply that NO_X should not be controlled, when it is known that nitrate replacement occurs under other common conditions.

The EPA recognizes that the relative reductions in $PM_{2.5}$ from implementation of the CAIR will be greater for SO_2 than for NO_X. Nevertheless, overall costs for reducing NO_X in the CAIR region are much lower than SO_2 because a large portion of the region has already installed NO_X controls for ozone in the summer months. Our revised modeling approaches took into account the differences commenters note between actual nitrate concentrations in the atmosphere and what is measured as $PM_{2.5}$. Nevertheless emissions of both pollutants clearly contribute to interstate transport of ambient fine particles, and EPA concludes that the best approach in this situation is to provide highly cost effective reductions for both pollutants. Moreover, in warmer conditions when apparent nitrate changes from NO_X reductions as measured on $PM_{2.5}$ monitors are small, the actual reductions in particulate and gaseous nitrates in the ambient environment are larger; accordingly, NO_X reductions combined with SO_2 reductions can be expected to reduce health risk, visibility impairment, and other environmental damages.

c. What Is EPA's Final Determination?

After considering the public comments, EPA concludes that it should adopt the approach it proposed for addressing interstate transport of pollutants that affect $PM_{2.5}$, for the reasons presented here and in the proposal. That is, in today's action, EPA is requiring states to take steps to control emissions of SO_2 and NO_X on the basis of their contributions to nonattainment of $PM_{2.5}$ standards in downwind states. The EPA concludes that we do not now have a sufficient basis for including emissions of other components (carbonaceous material, ammonia, and crustal material) that contribute to $PM_{2.5}$ in determining significant contributions and in requiring emission reductions of these components.

2. What Is the Role for Local Emissions Reduction Strategies?

a. Summary of Analyses and Conclusions in the Proposal

In section IV.F of the proposed rule, we discussed two analyses that were completed to address the impact of local control measures relative to regional reductions of SO_2 and NO_X (69 FR 4596–99). In the first analysis, we applied a list of readily identifiable control measures (NPR, Table IV–5) in the Philadelphia, Birmingham, and Chicago urban primary metropolitan statistical areas (PMSA) counties. In the second analysis, we applied a similar list of control measures to 290 counties representing the metropolitan areas we projected to contain any nonattainment county in 2010 in the baseline scenario. The three-city analysis estimated that these local measures would result in ambient $PM_{2.5}$ reductions of about 0.5 $\mu g/m^3$ to about 0.9 $\mu g/m^3$, which is less than needed to bring any of the cities into attainment in 2010. The 290-county study, which included enough counties to produce regional as well as local reductions, found that while some of the 2010 nonattainment areas would be projected to attain, many would not. Moreover, much of the $PM_{2.5}$ reduction in the 290-county study resulted from assuming reduction in sulfates due to SO_2 reductions on utility boilers in the urban counties. Accordingly, we concluded that for a sizable number of $PM_{2.5}$ nonattainment areas it will be difficult if not impossible to reach attainment unless transport is reduced to a much greater degree than by the simultaneous adoption of controls within only the nonattainment areas.

b. Summary and Response to Public Comments

A number of commenters supported EPA's conclusion that regional reductions are necessary given the difficulty in achieving local emission reductions, and given that they are generally more cost-effective. Generally, EPA agrees with these commenters.

Other commenters were critical of the local measures analysis, and recommended that EPA should consider a more appropriate mix of regional and local controls before requiring substantial expenditures for controls on power plants or other regional sources potentially affected by this rule. These commenters believed that the proposed rule did not represent the optimal emissions reduction strategy. Other commenters believed that the local measures analysis underestimated the achievable local emissions reductions. Some commenters believed that EPA should include local control measures in the baseline scenario for the analysis. Finally, some commenters questioned the feasibility of doing a local measures analysis at all, given the uncertainties in the analysis, the uncertainties regarding nonattainment boundaries, and the work to be done by State and local areas to identify and evaluate strategies.

The EPA continues to conclude that it would be difficult if not impossible for many nonattainment areas to reach attainment through local measures alone, and EPA finds no information in the comments to alter this conclusion. While recognizing the uncertainties in conducting such an analysis (as noted in the preamble to the proposed rule), we continue to believe that the two local measures scenarios represent a highly ambitious set of measures and emissions reductions that may in fact be difficult to achieve in practice. This analysis was not intended to precisely identify local measures that may be available in a particular area. The EPA believes that a strategy based on adopting highly cost effective controls on transported pollutants as a first step would produce a more reasonable, equitable, and optimal strategy than one beginning with local controls. The local measures analyses we conducted were not, however, intended to develop a specific or ''optimal'' regional and local attainment strategy for any given area. Rather, the analysis was intended to evaluate whether, in light of available local measures, it is likely to be necessary to reduce significant regional transport from upwind states. We continue to believe that the two local measures analyses that were conducted for the proposal rule strongly support the need for regional reductions of SO_2 and NO_X.

[31] Ibid.

[32] For example, West, J.J., A.S. Ansari, and S.N. Pandis (1999) Marginal $PM_{2.5}$, nonlinear aerosol mass response to sulfate reductions in the Eastern U.S., J. Air & Waste Manage. Assoc., 49: 1415–1424.

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B. What Is the Basis for EPA's Decision To Require Reductions in Upwind Emissions of NO_X To Address Ozone-Related Transport?

1. How Did EPA Determine Which Pollutants Were Necessary To Control To Address Interstate Transport for Ozone?

In the notice of proposed rulemaking, EPA provided the following characterization of the origin and distribution of 8-hour ozone air quality problems:

The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compound: VOCs and NO_X (mainly NO and NO_2). The term "VOC" includes many classes of compounds that possess a wide range of chemical properties and atmospheric lifetimes, which helps determine their relative importance in forming ozone. Sources of VOCs include man-made sources such as motor vehicles, chemical plants, refineries, and many consumer products, but also natural emissions from vegetation. Nitrogen oxides are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils. Key aspects of current and projected inventories for NO_X and VOC are summarized in section IV of the proposal notice and EPA websites (*e.g., http://www.w.gov/ttn/chief.*) The relative importance of NO_X and VOC in ozone formation and control varies with local- and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind.

The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.*, increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large-scale stagnation, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. The most recent authoritative assessments of ozone control approaches [33, 34] have concluded that, for reducing regional scale ozone transport, a NO_X control strategy would be most effective, whereas VOC reductions are most effective in more dense urbanized areas.

Studies conducted in the 1970s established that ozone occurs on a regional scale (*i.e.,* 1000s of kilometers) over much of the Eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas.[35, 36] While progress has been made in reducing ozone in many urban areas, the Eastern U.S. continues to experience elevated regional scale ozone episodes in the extended summer ozone season.

Regional 8-hour ozone levels are highest in the Northeast and Mid-Atlantic areas with peak 2002 (3-year average of the 4th highest value for all sites in the region) ranging from 0.097 to 0.099 parts per million (ppm).[37] The Midwest and Southeast States have slightly lower peak values (but still above the 8-hour standard in many urban areas) with 2002 regional averages ranging from 0.083 to 0.090 ppm. Regional-scale ozone levels in other regions of the country are generally lower, with 2002 regional averages ranging from 0.059 to 0.082 ppm. Nevertheless, some of the highest urban 8-hour ozone levels in the nation occur in southern and central California and the Houston area.

In the notice of proposed rulemaking, EPA noted that we continue to rely on the assessment of ozone transport made in great depth by the OTAG in the mid-1990s. As indicated in the NO_X SIP call proposal, the OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups reached the following conclusions:

A. Regional NO_X emissions reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.

B. Controls for VOC are effective in reducing ozone locally and are most advantageous to urban nonattainment areas. (62 FR 60320, November 7, 1997).

The EPA proposed to reaffirm this conclusion in this rulemaking, and proposed to address only NO_X emissions for the purpose of reducing interstate ozone transport.

Some commenters suggested that in this rulemaking EPA should require regional reductions in VOC emissions as well as NO_X emissions in this rulemaking.[38] The EPA continues to believe based on the OTAG and NARSTO reports cited earlier, and the modeling completed as part of the analysis for this rule, that NO_X emissions are chiefly responsible for regional ozone transport, and that NO_X reductions will be most effective in reducing regional ozone transport. This understanding was considered an adequate basis for controlling NO_X emissions for ozone transport in the NO_X SIP call, and was upheld by the courts. As a result, EPA is requiring NO_X reductions and not VOC reductions in this rulemaking.

However, EPA agrees, that VOCs from some upwind States do indeed have an impact in nearby downwind States, particularly over short transport distances. The EPA expects that States will need to examine the extent to which VOC emissions affect ozone pollution levels across State lines, and identify areas where multi-state VOC strategies might assist in meeting the 8-hour standard, in planning for attainment. This does not alter the basis for the CAIR ozone requirements in this rule; EPA's modeling supports the conclusion that NO_X emissions from upwind states will significantly contribute to downwind nonattainment and interfere with maintenance of the 8-hour ozone standard.

2. How Did EPA Determine That Reductions in Interstate Transport, as Well as Reductions in Local Emissions, Are Warranted To Help Ozone Nonattainment Areas To Meet the 8-Hour Ozone Standard?

a. What Did EPA Say in Its Proposal Notice?

In the NPR, EPA noted that the Agency promulgated the NO_X SIP call in 1998 to address interstate ozone transport problems in the Eastern U.S. The EPA noted that it made sense to re-evaluate whether the NO_X SIP call was adequate at the same time that the Agency was assessing the need for emissions reductions to address interstate $PM_{2.5}$ problems because of overlap in the pollutants and relevant

[33] Ozone Transport Assessment Group, OTAG Final Report, 1997.

[34] NARSTO, An Assessment of Tropospheric Ozone Pollution—A North American Perspective, July 2000.

[35] National Research Council, Rethinking the Ozone Problem in Urban and Regional Air Pollution, 1991.

[36] NARSTO, An Assessment of Tropospheric Ozone Pollution—A North American Perspective, July 2000.

[37] U.S. EPA, Latest Findings on National Air Quality, August 2003.

[38] Other commenters confirmed that the control of NO_X emissions is critical for interstate ozone transport, and supported EPA's decision not to include VOC emissions in this rule.

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sources, and the timetables for States to submit local attainment plans. The EPA presented a new analysis of the extent of residual 8-hour ozone attainment projected to remain in 2010, and the extent and severity of interstate pollution transport contributing to downwind nonattainment in that year.

The proposal notice said that based on a multi-part assessment, EPA had concluded that:

- ''Without adoption of additional emissions controls, a substantial number of urban areas in the central and eastern regions of the U.S. will continue to have levels of 8-hour ozone that do not meet the national air quality standards.
- * * * EPA has concluded that small contributions of pollution transport to downwind nonattainment areas should be considered significant from an air quality standpoint, because these contributions could prevent or delay downwind areas from achieving the standards.
- * * * EPA has concluded that interstate transport is a major contributor to the projected (8-hour ozone) nonattainment problem in the eastern U.S. in 2010. * * * (T)he nonattainment areas analyzed receive a transport contribution of more than 20 percent of the ambient ozone concentrations, and 21 of 47 had a transport contribution of more than 50 percent.
- Typically, two or more States contribute transported pollution to a single downwind area, so that the ''collective contribution'' is much larger than the contribution of any single State.

Also, EPA concluded that highly cost-effective reductions in NO_X emissions were available within the eastern region where it determined interstate transport was occurring, and that requiring those highly cost effective reductions would reduce ozone in downwind nonattainment areas.

In addition, the proposal examined the effect of hypothetical across-the-board emissions reductions in nonattainment areas. The notice stated that EPA had conducted a preliminary scoping analysis in which hypothetical total NO_X and VOC emissions reductions of 25 percent were applied in all projected nonattainment areas east of the continental divide in 2010, yet approximately 8 areas were projected to have ozone levels exceeding the 8-hour standard. Based on experience with state plans for meeting the one-hour ozone standard, EPA said this scenario was an indication that attaining the 8-hour standard will entail substantial cost in a number of nonattainment areas, and that further regional reductions are warranted.

b. What Did Commenters Say?

The Need for Reductions in Interstate Ozone Transport: Some commenters argued that EPA should not conduct another rulemaking to control interstate contributions to ozone because local contributions in nonattainment regions appear, according to the commenters, to have larger impacts than regional NO_X emissions. The commenters cited EPA's sensitivity modeling of hypothetical 25 percent reductions as supporting this view.

The EPA disagrees that comparing the sensitivity modeling and the CAIR control modeling is a valid way to compare the effectiveness of local and regional controls. The two scenarios do not reduce emissions by equal tonnage amounts, equal percentages of the inventory, or equal cost. These scenarios therefore do not support an assessment of the relative effectiveness of local and regional controls. While EPA in general agrees that emissions reductions in a nonattainment area will have a greater effect on ozone levels in that area than similar reductions a long distance away, EPA does not agree that the modeling supports the conclusion that all additional controls to promote attainment with the 8-hour standard should be local. The level of reduction assumed was a hypothetical level, not a level determined to be reasonable cost nor a mandated level of reduction. The commenters provided no evidence that reasonable local controls alone would result in attainment throughout the East. However, EPA did receive comments that such a level would result in costly controls and might not be feasible in some areas that have previously imposed substantial controls.

The EPA believes it is clear that further reductions in emissions contributing to interstate ozone transport, beyond those required by the NO_X SIP Call, are warranted to promote attainment of the 8-hour ozone standard in the eastern U.S. As explained elsewhere in this final rule, EPA analyzed interstate transport remaining after the NO_X SIP Call, and determined—considering both the impact of interstate transport on downwind nonattainment, and the potential for highly cost effective reductions in upwind States—that 25 States significantly contribute to 8-hour ozone nonattainment downwind. The importance of transport is illustrated, as mentioned above, by EPA's findings for the final rule that (1) all the 2010 nonattainment counties analyzed were projected to receive a transport contribution of 24 percent or more of the ambient ozone concentrations, and (2) that 16 of 38 counties are projected to have a transport contribution of more than 50 percent.

In addition, EPA received multiple comments from State associations and individual States strongly agreeing that further reductions in interstate ozone transport are warranted to promote attainment with the 8-hour standard, to protect public health, and to address equity concerns of downwind states affected by transport. For example, comments from the Maryland Department of the Environment stated, ''Our 15 year partnership with researchers from the University of Maryland has produced data that shows on many summer days the ozone levels floating into Maryland area are already at 80 to 90 percent of the 1-hour ozone standard and actually exceed the new 8-hour ozone standard before any Maryland emissions are added. * * * Serious help is needed from EPA and neighboring states to solve Maryland's air pollution problems. * * * Local reductions alone will not clean up Maryland's air.'' The comments of the Ozone Transport Commission stated that even after levels of control envisioned by EPA in 2010 (under the Clear Skies Act), interstate transport from other states would continue to affect the Ozone Transport Region created by the CAA (Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia). ''Our modeling demonstrates that even in the extreme example of zero anthropogenic emissions within the OTR (Ozone Transport Region), 145 of 146 monitors show a significant (>25%) increment of the 8-hour standard taken up by transport from outside the OTR.'' Comments from the North Carolina Department of Environment and Natural Resources stated, ''The reductions proposed in [EPA's rule] in the other states are needed to ensure that North Carolina can attain and maintain the health-based air quality standards for * * * 8-hour ozone.''

Magnitude of Ozone Reductions Achieved: Commenters stated that NO_X reductions should not be pursued because the 8-hour ozone reductions in projected nonattainment counties resulting from the required NO_X reductions are too small—1–2 ppb in only certain areas. According to commenters, these benefits are smaller than the threshold for determining significant contribution.

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The EPA disagrees with the notion that if air quality improvements would be limited, then nothing further should be done to address interstate transport. Based on the difference between the base case and CAIR control case modeling results, EPA has concluded that interstate air quality impacts are significant from an air quality standpoint, and that highly cost effective reductions are available to reduce ozone transport. State comments have corroborated EPA's conclusion that a number of areas will face high local control costs, or even be unable to attain the 8-hour ozone standard, without further reductions in interstate transport. Therefore, EPA believes it is important for upwind states to modify their SIPs so that they contain adequate provisions to prohibit significant contributions to downwind nonattainment or interference with maintenance as the statute requires. The EPA has established an amount of required emissions reductions based on controls that are highly cost effective. The resulting improvements in downwind ozone levels are needed for attainment, public health and equity reasons.

The 2 ppb significance threshold that commenters cite is part of the test that EPA used to identify which States should be evaluated for inclusion in a rule requiring them to reduce emissions to reduce interstate transport. (See section VI.) This 2 ppb threshold is based on the impact on a downwind area of eliminating *all* emissions in an upwind State. The ozone reductions from CAIR will improve public health and will decrease the extent and cost of local controls needed for attainment in some areas. In addition, base case modeling for this rule shows that of the 40 counties projected in nonattainment in 2010, 16 counties are within 2 ppb of the standard, 6 counties are within 3 ppb, and 3 counties are within 4 ppb. In 2015, projected base case ozone concentrations in over 70 percent of nonattaining counties (*i.e.*, 16 of 22 counties) are within 5 ppb of the standard.

Reducing NO_X emissions has multiple health and environmental benefits. Controlling NO_X reduces interstate transport of fine particle levels as well as ozone levels, as discussed elsewhere in this notice. Although EPA is not relying on other benefits for purposes for setting requirements in this rule, reducing NO_X emissions also helps to reduce unhealthy ozone and PM levels within a State, as well as reduce acid deposition to soils and surface waters, eutrophication of surface and coastal waters, visibility degradation, and impacts on terrestrial and wetland systems such as changes in species composition and diversity.

EPA's Authority To Require Controls Beyond the NO_X SIP Call: Commenters emphasized that in the NO_X *SIP Call, EPA determined the States whose emissions contribute significantly to nonattainment, EPA mandated NO_X* emissions reductions that would eliminate those significant contributions, and EPA indicated that it would reconsider the matter in 2007. This commenter argued that for the States included in the NO_X SIP Call, EPA may not, as a legal matter, conduct further rulemaking at this time because the affected States are no longer contributing significantly to nonattainment downwind. In any event, the commenters said, EPA should abide by its statement that it would revisit the matter in 2007, and EPA should not do so earlier.

Sound policy considerations support re-examining interstate ozone transport at this time. At the time of the NO_X SIP Call, EPA anticipated reassessing in 2007 the need for additional reductions in emissions that contribute to interstate transport, but EPA has accelerated that date in light of various circumstances, including the fact that we are undertaking similar action with the $PM_{2.5}$ NAAQS. In addition, in light of overlap in the pollutants, States, and sources likely to be affected, it is prudent to coordinate action under the 8-hour ozone standard. The EPA notes that evaluating $PM_{2.5}$ transport and ozone transport together at this time will enable States to consider the resulting rules in devising their $PM_{2.5}$ and 8-hour ozone attainment plans, and will enable States and sources to plan emissions reductions knowing their transport-related reduction requirements for both standards.

CAA section 110(a)(2)(D) requires that State SIPs contain ''adequate provisions'' prohibiting emissions that significantly contribute to nonattainment areas in, or interfere with maintenance by, other States. Over time, emissions of ozone precursors, the (projected) non-attainment status of receptors, the modeling tools that EPA and the states use to conduct their analyses, the data available to the states or EPA and other analytic tools or conditions may change. The EPA has conducted an updated analysis of upwind contribution to downwind nonattainment of 8-hour ozone nonattainment areas after the NO_X SIP Call, including updated emissions projections, updated air quality modeling, and updated analysis of control costs. This has revealed a need for reductions beyond those required by the NO_X SIP Call in order for upwind states to be in compliance with section 110(a)(2)(D). The EPA thus disagrees with commenters' assertions that the provisions of section 110(a)(2)(D) prevent EPA from conducting further evaluation of upwind contributions to downwind nonattainment at this time. The EPA also notes that the NO_X SIP Call, a 1998 rulemaking, promulgated a set of requirements intended to eliminate significant contribution to downwind ozone nonattainment at the time of implementation, which EPA identified on the basis of modeling for the year 2007 (although implementation was required to occur several years earlier). In today's action, EPA is reviewing the transport component of 8-hour ozone nonattainment for the period beginning in 2010, consistent with the criteria in the NO_X SIP Call as applied to present circumstances, concluding that even with implementation of the NO_X SIP Call controls, upwind States will contribute significantly to downwind ozone nonattainment and interfere with maintenance at a point after 2007. No provision of the CAA prohibits this action.

Commenters added that the purpose of the CAIR rulemaking seemed to be to account for the fact that control costs have changed since the date of the NO_X SIP Call. The commenters said that control costs will frequently fluctuate, but that such fluctuations should not merit revised rulemaking.

In response, we would note that EPA conducted an updated analysis for air quality impacts, not only costs, in determining that further reductions in interstate ozone transport are warranted. That air quality analysis showed a substantial, continuing interstate transport problem for areas after implementation of the NO_X SIP Call. The EPA does have the legal authority to reconsider the scope of the area that significantly contributes and the level of control determined to be ''highly cost-effective'' based on new information. Updated information shows that lower NO_X burners and SCR achieve better performance than previously estimated and as a result are more cost effective than previously anticipated. This rule follows the NO_X SIP Call by six years; EPA does not believe that this represents a too-frequent re-evaluation, particularly given the stay of the 8-hour basis for the NO_X SIP Call (*See, e.g.,* CAA section 109(d)(1) requiring EPA to reevaluate the NAAQS themselves every five years.) So both updated air quality and cost information supports further

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NO_X controls to reduce interstate transport.

Some commenters argued that EPA should delay imposing control obligations on upwind States for the 8-hour ozone NAAQS until after EPA has implemented local control requirements, and after all of the NO_X SIP Call control requirements are implemented and evaluated. Others said EPA should not impose requirements on non-SIP-Call States until after all 8-hour controls—NO_X SIP Call and local—are implemented.

We agree that the NO_X SIP Call should be taken into account in evaluating the need for further interstate transport controls. We have taken the NO_X SIP Call into account by including the effect of the NO_X SIP Call in the base case used for the CAIR analysis, and by conducting analyses to confirm that CAIR will achieve greater ozone-season reductions than the SIP Call. The EPA disagrees that the Agency should wait for implementation of local controls before determining transport controls. There is no legal requirement that EPA wait to determine transport controls until after local controls are implemented. The EPA's basis for this legal interpretation is explained in section II.A. above. In addition, the Agency believes it is important to address interstate transport expeditiously for public health.

C. Comments on Excluding Future Case Measures From the Emissions Baselines Used To Estimate Downwind Ambient Contribution

The EPA received comments that the 2010 analytical baseline for evaluating whether upwind emissions meet the air quality portion of the ''contribute significantly'' standard should reflect local control measures that will be required in the downwind nonattainment areas, or broader statewide measures in downwind states, to attain the $PM_{2.5}$ or 8-hour ozone NAAQS by the relevant attainment dates, many of which are (or are anticipated to be) 2010 or earlier. This single target year was chosen both to address analytical tool constraints and to reasonably reflect future conditions in or near the initial attainment years for both ozone and PM nonattainment areas. The EPA did include in the baseline most of the specifically required measures that can be identified at this time, but did not include any further measures that would be needed for satisfying ''rate of progress'' requirements or for attainment of the $PM_{2.5}$ and 8-hour ozone standards. If EPA had included further local controls, the commenters contend, fewer upwind States would have exceeded our significant contribution thresholds.

We reject any notion that in determining the need for transport controls in upwind states, EPA should assume that the affected downwind areas must ''go all the way first''—that is, assume that downwind areas put on local in-state controls sufficient to reach attainment, or assume that downwind states with nonattainment areas implement statewide control measures. The EPA does not believe these are appropriate assumptions. The former assumption would eviscerate the meaning of CAA section 110(a)(2)(D). The latter assumption would make the downwind state solely responsible for reductions in any case where a downwind state could attain through in-state controls alone, even if the upwind state contribution was significantly contributing to nonattainment problems in the downwind state. We do not believe that this approach would be consistent with the intent of section 110(a)(2)(D), which in part is to hold upwind states responsible for an appropriate share of downwind nonattainment and maintenance problems, and to prevent scenarios in which downwind states must impose costly extra controls to compensate for significant pollution contributions from uncontrolled or poorly controlled sources in upwind states. In addition, this approach could raise costs of meeting air quality standards because highly cost effective controls in upwind States would be foregone.

Rather, in the particular circumstances presented here, we think the adoption of regional controls at this time under section 110(a)(2)(D) is consistent with sound policy and section 110. Based on our analysis, the states covered by CAIR make a significant contribution to downwind nonattainment and the required reductions are highly cost effective. The reductions will reduce regional pollution problems affecting multiple downwind areas, will make it possible for States to determine the extent of local control needed knowing the reductions in interstate pollution that are required, will address interstate equity issues that can hamper control efforts in downwind States, and reflect considerations discussed in detail in section VII.

Although some commenters advocated specifically including statutorily mandated future nonattainment area controls in the analytical baseline, it would be difficult as a practical matter to predict the extent of local controls that will be required (beyond controls previously required) in each area in advance of final implementation rules interpreting the Act's requirements for $PM_{2.5}$ and 8-hour ozone, and before the state implementation plan process. Subpart 2 provisions that apply to certain ozone nonattainment areas are quite specific regarding some mandatory measures; we believe the CAIR baseline for the most part captures these measures. (See Response to Comments document in the docket.) As noted above, the choice of a single analytical year of 2010 was made to reflect baseline conditions at a date at or near the attainment dates for different pollutants and classes of areas. Because the attainment date for many ozone areas is 2009 or earlier, it should be noted that the analyses in 2010 may slightly overestimate the benefits of a number of national rules for mobile sources that grow with time. As noted elsewhere, these differences are unlikely to be significant.

D. What Criteria Should Be Used To Determine Which States Are Subject to This Rule Because They Contribute to $PM_{2.5}$ Nonattainment?

1. What Is the Appropriate Metric for Assessing Downwind $PM_{2.5}$ Contribution?

a. Notice of Proposed Rulemaking

In the NPR, we proposed as the metric for identifying a State as significantly contributing (depending upon further consideration of costs) to downwind nonattainment, the predicted change, due to the upwind State's emissions, in $PM_{2.5}$ concentration in the downwind nonattainment area that receives the largest ambient impact. The EPA proposed this metric in the form of a range of alternatives for a ''bright line,'' that is, ambient impacts at or greater than the chosen threshold level indicated that the upwind State's emissions do contribute significantly (depending on cost considerations), and that ambient impacts below the threshold mean that the upwind State's emissions do not contribute significantly to nonattainment. As detailed in section VI below, EPA conducted the analysis through air quality modeling that removed the upwind State's anthropogenic SO_2 and NO_X emissions, and determined the difference in downwind ambient $PM_{2.5}$ levels before and after removal. The modeling results indicate a wide range of maximum downwind nonattainment impacts from the 37 States that we evaluated. The largest maximum contribution is 1.67 micrograms per cubic meter ($\mu g/m^3$), from Ohio to both Allegheny and Beaver counties in Pennsylvania.

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b. Comments and EPA's Responses

The EPA proposed to use the maximum contribution on any downwind nonattainment area for assessing downwind $PM_{2.5}$ contributions. Many commenters expressed agreement with our proposed metric, however, many others disagreed. One group of these commenters indicated that EPA should distinguish the relative contribution from States using two parameters: (1) How many downwind nonattainment receptors they contribute to, and (2) how much they contribute to each such receptor. The commenters indicated that this approach would avoid inequities created by the disproportionate impact of some upwind contributors on their downwind neighbors. The EPA interprets these comments to suggest a metric that collectively includes both of these parameters, such as the sum of all downwind impacts on all affected receptors. This metric would result in higher values for States contributing to multiple receptors and at relatively high levels, and lower values for States contributing to fewer receptors and at relatively low levels.

The EPA's proposed metric does address how much each State contributes to a downwind neighbor; however, EPA does not believe that multiple downwind receptors need to be impacted in order for a particular state to be required to make emissions reductions under CAA section 110(a)(2)(D). Under this provision, an upwind State must include in the SIP adequate provisions that prohibit that State's emissions that ''contribute significantly to nonattainment in * * * *any other State* * * *.'' (Emphasis added.) Our interpretation of this provision is that the emphasized terms make clear that the upwind State's emissions must be controlled as long as they contribute significantly to a single nonattainment area.

One commenter agreed with EPA's use of maximum annual average downwind contribution, but suggested that EPA consider additional metrics such as: (a) Contributions to adverse health and welfare effects from short-term $PM_{2.5}$ concentrations; (b) contributions to worst 20 percent haze levels in Class 1 areas; and (c) contributions to adverse effects of sulfur and nitrogen deposition to acid sensitive surface waters and forest soils. The EPA appreciates that these metrics all have merit in their focus on the health and environmental consequences of emissions, however, in determining a metric for significant contributions, we must focus on implementation of CAA section 110(a)(2)(D) provisions regarding significant contribution to nonattainment of the $PM_{2.5}$ NAAQS.

Another commenter suggested EPA use the maximum annual average impact, as we proposed, but add the maximum daily $PM_{2.5}$ contribution. The commenter notes that this additional metric would indicate whether specific meteorological events drive the concentration change or whether there is a consistent pattern of transport from one area to another. It is not clear to EPA how the single data point of the maximum daily contribution indicates a consistent pattern of transport from one area to another since it is a measure from only a single day. Further, EPA does not agree that multiple days of impact is a relevant criterion for evaluating whether a State contributes significantly to nonattainment, since in theory, a single high-contribution event could be the cause or a substantial element of nonattainment of the annual average $PM_{2.5}$ standard. Because we currently do not observe nonattainment of the daily average $PM_{2.5}$ standard in Eastern areas, nonattainment of the annual average $PM_{2.5}$ standard is the relevant evaluative measure.

Some commenters suggested separately evaluating the NO_X- and SO_2-related impacts (*i.e.*, particulate nitrate and particulate sulfate) on nonattainment. As discussed in section II of this notice, EPA's approach to evaluating a State's impact on downwind nonattainment by considering the entirety of the State's SO_2 and NO_X emissions is consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to complex chemical reactions.

c. Today's Action

The EPA continues to believe that for each upwind State analyzed, the change in the annual $PM_{2.5}$ concentration level in the downwind nonattainment area that receives the largest impact is a reasonable metric for determining whether a State passes the ''air quality'' portion of the ''contribute significantly'' test, and therefore that State should be considered further for emissions reductions (depending upon the cost of achieving those reductions). This single concentration-based metric is adequate to capture the impact of SO_2 and NO_X emissions on downwind annual $PM_{2.5}$ concentrations.

2. What Is the Level of the $PM_{2.5}$ Contribution Threshold?

a. Notice of Proposed Rulemaking

In the NPR, EPA proposed to establish a State-level annual average $PM_{2.5}$ contribution threshold from anthropogenic SO_2 and NO_X emissions that was a small percentage of the annual air quality standard of 15.0 $\mu g/m^3$. The EPA based this proposal on the general concept that an upwind State's contribution of a relatively low level of ambient impact should be regarded as significant (depending on the further assessment of the control costs). We based our reasoning on several factors. The EPA's modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In addition, our analysis of ''base case'' $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind States, along with contributions from in-State sources and, in some cases, substantially larger contributions from a subset of particular upwind States. In the NO_X SIP Call rulemaking, we termed this pattern of contribution—which is also present for ozone nonattainment—''collective contribution.''

In the case of $PM_{2.5}$, we have found collective contribution to be a pronounced feature of the $PM_{2.5}$ transport problem, in part because the annual nature of the $PM_{2.5}$ NAAQS means that throughout the entire year and across a range of wind patterns—rather than during just one season of the year or on only the few worst days during the year which may share a prevailing wind direction—emissions from many upwind States affect the downwind nonattainment area.

As a result, to address the transport affecting a given nonattainment area, many upwind States must reduce their emissions, even though their individual contributions may be relatively small. Moreover, as noted above, EPA's air quality modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In combination, these factors suggest a relatively low value for the $PM_{2.5}$ transport contribution threshold is appropriate. For reasons specified in the NPR (69 FR 4584), EPA initially proposed a value of 0.15 $\mu g/m^3$ (1% of the annual standard) for the significance criterion, but also presented analyses based on an alternative of 0.10 $\mu g/m^3$ and called for comment on this alternative as well as on ''the use of

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higher or lower thresholds for this purpose'' (69 FR 4584).

The EPA adopted a conceptually similar approach to that outlined above for determining that the significance level for ozone transport in the NO_X SIP Call rulemaking should be a small number relative to the NAAQS. The DC Circuit Court, in generally upholding the NO_X SIP Call, viewed this approach as reasonable. *Michigan* v. *EPA,* 213 F.3d 663, 674–80 (DC Cir. 2000), *cert. denied,* 532 U.S. 904 (2001). After describing EPA's overall approach of establishing a significance level and requiring States with impacts above the threshold to implement highly cost-effective reductions, the Court explained: ''EPA's design was to have a lot of States make what it considered modest NO_X reductions * * *. '' *Id.* at 675. Indeed, the Court intimated that EPA could have established an even lower threshold for States to pass the air quality component:

> The EPA has determined that ozone has some adverse health effects—however slight—at every level [citing National Ambient Air Quality Standards for Ozone, 62 FR 38856 (1997)]. Without consideration of cost it is hard to see why any ozone-creating emissions should not be regarded as fatally ''significant'' under section 110(a)(2)(D)(i)(I).''
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> 213 F.3d at 678 (emphasis in original).

We believe the same approach applies in the case of $PM_{2.5}$ transport.

b. Comments and EPA's Responses

Many commenters indicated that EPA did not adequately justify the proposed annual average $PM_{2.5}$ contribution threshold level of 0.15 $\mu g/m^3$. Some commenters favor the alternative 0.10 $\mu g/m^3$ proposed by EPA, citing their agreement with EPA's rationale for 0.10 $\mu g/m^3$ while criticizing as arbitrary EPA's rationale for 0.15 $\mu g/m^3$.

Some commenters argued that the public health impact portion of EPA's rationale for establishing a relatively low-level threshold was not relevant. The commenters said that EPA previously determined, in establishing the $PM_{2.5}$ NAAQS, that ambient levels at or above 15.0 $\mu g/m^3$ were of concern for protecting public health, not the much lower levels that EPA proposed as the thresholds. In the NPR, we stated that we considered that there are significant public health impacts associated with ambient $PM_{2.5}$, even at relatively low levels. In generally upholding the NO_X SIP Call, the DC Circuit noted a similar reason for establishing a relatively low threshold for ozone impacts. *Michigan* v. *EPA,* 213 F.3d 663, 678 (DC Cir. 2000), cert. denied, 532 U.S. 904 (2001). The EPA notes that by using a metric that focuses on the contribution of upwind areas to downwind areas that are above 15.0 $\mu g/m^3$, relatively low contributions to levels above the annual $PM_{2.5}$ standard are highly relevant to public health protection.

Many commenters offered alternative thresholds higher than 0.15 $\mu g/m^3$, citing previous EPA rules or policies as justification for the alternative level. Some suggested the $PM_{2.5}$ threshold should be equivalent in percentage terms to the threshold employed for assessing maximum downwind 8-hour ozone contributions. The threshold for maximum downwind 8-hour ozone concentration impact used in the NO_X SIP Call, and proposed for use in the CAIR, is 2 parts per billion (ppb), or about 2.5 percent of the standard level of 80 ppb. Applying the 2.5 percent criterion to the 15.0 $\mu g/m^3$ annual $PM_{2.5}$ standard would yield a significance threshold of 0.35 $\mu g/m^3$.

The EPA disagrees with the comment that the thresholds for annual $PM_{2.5}$ and 8-hour ozone should be an equivalent percentage of their respective NAAQS. Both the forms and averaging times of the two standards are substantially different, with 8-hour ozone based on the average of the 4th highest daily 8-hour maximum values from each of 3 years, and $PM_{2.5}$ based on the average of annual means from 3 successive years. These fundamental differences in time scales, and thus in the patterns of transport that are relevant to contributing to nonattainment, do not suggest a transparent reason for presuming that the contribution thresholds should be equivalent. As discussed above, when more States make smaller individual contributions because of the annual nature of the $PM_{2.5}$ standard, it makes sense to have a threshold for $PM_{2.5}$ that is a smaller percentage of its NAAQS.

Other commenters suggested that in setting the maximum downwind $PM_{2.5}$ threshold, EPA should take into consideration the measurement precision of existing $PM_{2.5}$ monitors. The commenters assert that such measurement carries ''noise'' in the range of 0.5—0.6 $\mu g/m^3$. Because many daily average monitor readings are averaged to calculate the annual average, the precision of the annual average concentration is better than the figures cited by the commenters. Indeed, the annual standard is expressed as 15.0 $\mu g/m^3$, rounded to the nearest $^1/_{10}$ μg, because such small differences are meaningful on an annual basis. While disagreeing with the specific amounts suggested by commenters, EPA recognizes that the $PM_{2.5}$ threshold specified in the proposal contains two digits beyond the decimal place, while the NAAQS specifies only one. The EPA agrees that specification of a threshold value of 0.15 $\mu g/m^3$ does suggest an overly precise test that might need to take into account modeled difference in $PM_{2.5}$ values as low as 0.001 $\mu g/m^3$.

Other commenters indicated that modeling ''noise''—that is, imprecision—is a relevant consideration for establishing a threshold whose evaluation depends on air quality modeling analysis. These commenters indicated that a threshold of 5 percent of the NAAQS (*i.e.*, 0.75 $\mu g/m^3$) is more reasonable considering modeling sensitivity. The commenters were not clear about what they mean by modeling ''noise'' and did not explain how it relates to the use of a threshold metric in the context of the CAIR.

In responding to the comment, we have considered some possible contributors to what the commenter describes as ''noise.'' There is the possibility that the air quality model has a systematic bias in predicting concentrations resulting from a given set of emissions sources. The EPA uses the model outputs in a relative, rather than an absolute, sense so that any modeling bias is constrained by real world results. As described further in section VI, EPA conducts a relative comparison of the results of a base case and a control case to estimate the percentage change in ambient $PM_{2.5}$ from the current year base case, holding meteorology, other source emissions, and other factors contributing to uncertainty constant. With this technique, any absolute modeling bias is cancelled out because the same model limitations and uncertainties are present in each set of runs.

Another possible source of noise is in the relative comparison of two model runs conducted on different computers. Since the computers used by EPA to run air quality models do not have any significant variability in their numerical processes, two model runs with identical inputs result in outputs that are identical to many significant digits. On the other hand, EPA believes it is not appropriate or necessary to carry such results to a level of precision that is beyond that required by the $PM_{2.5}$ NAAQS itself [39].

Many commenters noted that EPA's proposed threshold of 0.15 $\mu g/m^3$, or one percent of the annual $PM_{2.5}$ NAAQS of 15.0 $\mu g/m^3$, is lower than the single-source contribution thresholds

[39] In attainment modeling for the annual $PM_{2.5}$ NAAQS, results are carried to the second place beyond the decimal, in contrast to the three places beyond decimal noted above for the proposed threshold.

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employed for PM_{10} in certain other regulatory contexts. Commenters cited several different thresholds, including thresholds governing the applicability of the preconstruction review permit program and the emissions reduction requirement for certain major new or modified stationary sources located in attainment or unclassified areas;[40] and thresholds in the PSD rules that may relieve proposed sources from performing comprehensive ambient air quality analyses.[41]

Since the thresholds referred to by the commenters serve different purposes than the CAIR threshold for significant contribution, it does not follow that they should be made equivalent. The implication of the thresholds cited by the commenters is not that single-source contributions below these levels indicate the absence of a contribution. Rather, these thresholds address whether further more comprehensive, multi-source review or analysis of appropriate control technology and emissions offsets are required of the source. A source with estimated impacts below these levels is recognized as still affecting the airshed and is subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality. The purpose of the CAIR threshold for $PM_{2.5}$ is to determine whether the annual average contribution from a collection of sources in a State is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective.

One commenter suggested that EPA also establish and evaluate a threshold for a potential new tighter 24-hour $PM_{2.5}$ standard (*e.g.*, 1 percent of 30 μg/m³). The EPA must base its criteria on evaluation of the current $PM_{2.5}$ standards and not standards that may be considered in the future.

c. Today's Action

The EPA continues to believe that the threshold for evaluating the air quality component of determining whether an individual State's emissions ''contribute significantly'' to downwind nonattainment of the annual $PM_{2.5}$ standard, under CAA section 110(a)(2)(D) should be very small compared to the NAAQS. We are, however, persuaded by commenters arguments on monitoring and modeling that the precision of the threshold should not exceed that of the NAAQS. Rounding the proposal value of 0.15, the nearest single digit corresponding to about 1% of the $PM_{2.5}$ annual NAAQS is 0.2 μg/m³. The final rule is based on this threshold. The EPA has decided to apply this threshold such that any model result that is below this value (0.19 or less)indicates a lack of significant contribution, while values of 0.20 or higher exceed the threshold.[42]

Using this metric for determining whether a State ''contributes significantly'' (before considering cost) to $PM_{2.5}$ nonattainment, our updated modeling shows that Kansas, Massachusetts, New Jersey, Delaware, and Arkansas (all included in the original proposal) no longer exceed the 0.2 μg/m³ annual average $PM_{2.5}$ contribution threshold. Of these states, only Arkansas would exceed the threshold of 0.15 μg/m³ that was included in the proposal.

E. What Criteria Should Be Used To Determine Which States Are Subject to This Rule Because They Contribute to Ozone Nonattainment?

1. Notice of Proposed Rulemaking

In assessing the contribution of upwind States to downwind 8-hour ozone nonattainment, EPA proposed to follow the approach used in the NO_X SIP Call and to employ the same contribution metrics, but with an updated model and updated inputs that reflect current requirements (including the NO_X SIP Call itself).[43]

The air quality modeling approach we proposed to quantify the impact of upwind emissions includes two different methodologies: Zero-out and source apportionment. As described in section VI, EPA applied each methodology to estimate the impact of all of the upwind State's NO_X emissions on each downwind nonattainment areas.

The EPA's first step in evaluating the results of these methodologies was to remove from consideration those States whose upwind contributions were very low. Specifically, EPA considered an upwind State not to contribute significantly to a downwind nonattainment area if the State's maximum contribution to the area was either (1) less than 2 ppb, as indicated by either of the two modeling techniques; or (2) less than one percent of total nonattainment in the downwind area.[44]

If the upwind State's impact exceeded these thresholds, then EPA conducted a further evaluation to determine if the impact was high enough to meet the air quality portion of the ''contribute significantly'' standard. In doing so, EPA organized the outputs of the two modeling techniques into a set of ''metrics.'' The metrics reflect three key contribution factors:

- The magnitude of the contribution (actual amount of ozone contributed by emissions in the upwind State to nonattainment in the downwind area);
- The frequency of the contribution (how often contributions above certain thresholds occur); and
- The relative amount of the contribution (the total ozone contributed by the upwind State compared to the total amount of nonattainment ozone in the downwind area).

The specific metrics on which EPA proposed to rely are the same as those used in the NO_X SIP Call. Table III–1 lists them for each of the two modeling techniques, and identifies their relationship to the three key contribution factors.

[40] *See* 40 CFR 51.165(b)(2). New or modified major sources in attainment or unclassifiable areas must undergo preconstruction permit review, adopt best available control technology, and obtain emissions offsets if they are determined to ''cause or contribute'' to a violation of the NAAQS. ''Cause or contribute'' is defined as an impact that exceeds 5 μg/m³ (3.3 percent) of the 150 μg/m³ 24-hour average PM_{10} NAAQS , or 1 μg/m³ (2 percent) of the annual average PM_{10} NAAQS.

[41] *See* 40 CFR 51.166(i)(5)(i). Proposed new sources or existing-source modifications that would contribute less than 10 μg/m³ (or 5.3%) of the 150 μg/m³ PM_{10} 24-hour average NAAQS, estimated using on a screening model, may avoid the requirement of collecting and submitting ambient air quality data.

[42] This truncation convention for $PM_{2.5}$ is similar to that used in evaluating modeling results in applying the ozone significance screening criterion of 2 ppb in the NO_X SIP call and the CAIR proposal (Technical Support Document for the Interstate Air Quality Rule Air Quality Modeling Analyses'', January 2004. Docket # OAR–2003–0053–0162), as well as today's final action.

[43] Today's action, including the updated modeling, fulfills EPA's commitment in the NO_X SIP Call (which EPA finalized in 1998) to reevaluate interstate ozone contributions by 2007. *See* 63 FR 57399; October 27, 1998.

[44] See the CAIR Air Quality Modeling TSD for description of the methodology used to calculate these metrics.

TABLE III–1.—OZONE CONTRIBUTION FACTORS AND METRICS

Factor	Modeling technique	
	Zero-out	Source apportionment
Magnitude of Contribution	Maximum contribution	Maximum contribution; and Highest daily average contribution (ppb and percent).
Frequency of Contribution	Number and percent of exceedances with contributions in various concentration ranges.	Number and percent of exceedances with contributions in various concentration ranges.
Relative Amount of Contribution	Total contribution relative to the total exceedance ozone in the downwind area; and. Population-weighted total contribution relative to the total population-weighted exceedance ozone in the downwind area.	Total average contribution to exceedance hours in the downwind area.

In the NPR, EPA proposed threshold values for the metrics. An upwind State whose contribution to a downwind area exceeded the threshold values for at least one metric in each of at least two of the three sets of metrics was considered to contribute significantly (before considering cost) to that downwind area. To reiterate, the three sets of metrics reflect the factors of magnitude of contribution, frequency of contribution, and relative percentage on nonattainment.

In fact, EPA noted in the NPR that for each upwind State, the modeling disclosed at least one linkage with a downwind nonattainment area in which all factors (magnitude, frequency, and relative amount) were found to indicate large and frequent contributions. In addition, EPA noted in the NPR that each upwind State contributed to nonattainment problems in at least two downwind States (except for Louisiana and Arkansas which contributed to nonattainment in only 1 downwind State).

In addition, EPA noted in the NPR that for most of the individual linkages, the factors yield a consistent result across all three sets of metrics (*i.e.*, either (i) large and frequent contributions and high relative contributions or (ii) small and infrequent contributions and low relative contributions). In some linkages, however, not all of the factors are consistent. The EPA believes that each of the factors provides an independent, legitimate measure of contribution.

In the NPR, EPA applied the evaluation methodology described above to each upwind-downwind linkage to determine which States contribute significantly (before considering cost) to nonattainment in the 40 downwind counties in nonattainment for ozone in the East. The analysis of the metrics for each linkage was presented in the AQMTSD for the NPR. The modeling analysis supporting the final rule is an update to the NPR modeling, and is described in more detail in section VI below.

2. Comments and EPA Responses

Some commenters submitted comments specifically on the 8-hour ozone metrics. One commenter asserted that in calculating the ''Relative Amount of Contribution'' metric, EPA treats the modeled reductions from zeroing out a State's emissions as impacting only the portion of the downwind receptor's ambient ozone level that exceeds the 8-hour average 84 ppb level. The commenter asserted that this approach falsely treats the upwind state's emissions as contributing to the amount of ozone that exceeds the NAAQS, and thus inflates the ambient impact of those emissions. The commenter concluded that it would be more appropriate to treat the upwind emissions as impacting all of the downwind ozone level (not just the portion greater than 84 ppb). We interpret this comment to mean that in expressing an upwind State's contribution as a percentage, the denominator of the percentage should be the downwind area's total ozone contribution, rather than the downwind area's ozone excess above the NAAQS, but that the same threshold should be used to evaluate contribution. This would tend to result in fewer upwind States being found to be significant with respect to this metric.

We believe that it is important to examine the ozone contribution relative to the amount of ozone above the NAAQS as well as the amount relative to total nonattainment ozone. Both approaches have merit. The intent of the relative contribution metric, as calculated for the zero-out modeling, is to view the contribution of the upwind State relative to the amount that the downwind area is in nonattainment; that is, the amount of ozone above the NAAQS. However, our relative amount metric for the source apportionment modeling does treat the amount of contribution relative to the total amount of ozone when ozone concentrations are predicted to be above the NAAQS. To be found a significant contributor, an upwind State must be above the threshold for both the zero-out-based metric and the source-apportionment-based metric. Thus, our approach to considering the significance of interstate ozone transport captures both approaches for examining the relative amount of contribution and does not favor one approach over the other, as discussed above.

3. Today's Action

The EPA is finalizing the methodology proposed in the NPR, and discussed above, for evaluating the air quality portion of the ''contribute significantly'' standard for ozone.

F. Issues Related to Timing of the CAIR Controls

1. Overview

A number of commenters questioned the need for CAIR requirements considering that cap dates of 2010 and 2015 are later than the attainment dates that, in the absence of extensions, would apply to certain downwind $PM_{2.5}$ areas and ozone nonattainment areas. Other commenters, noting that states will be required to adopt controls in local attainment plans, questioned whether CAIR controls would still be needed to avoid significant contribution to downwind nonattainment, or whether the controls would still be needed to the extent required by the rule.

Of course, CAIR will achieve substantial reductions in time to help many nonattainment areas attain the standards by the applicable attainment dates. The design of the SO_2 program, including the declining caps in 2010 and 2015 and the banking provisions, will steadily reduce SO_2 emissions over time, achieving reductions in advance of the cap dates; and the 2009 and 2015 NO_X reductions will be timely for many downwind nonattainment areas.

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Although many of today's nonattainment areas will attain before all the reductions required by CAIR will be achieved, it is clear that CAIR's reductions will still be needed through 2015 and beyond. The EPA's air quality modeling has demonstrated that upwind States have a sufficiently large impact on downwind areas to require reductions in 2010 and 2015 under CAA section 110(a)(2)(D). Under this provision, SIPs must prohibit emissions from sources in amounts that ''will contribute significantly to * * * nonattainment'' or ''will interfere with maintenance''.[45] The EPA has evaluated the attainment status of the downwind receptors in 2010 and 2015, and has determined that each upwind State's 2010 and 2015 emissions reductions are necessary to the extent required by the rule because a downwind receptor linked to that upwind State will either (i) remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind State's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory.

The argument that the CAIR reductions are justified, in part, by the need to prevent interference with maintenance, is a limited one. The EPA does not believe that the ''interfere with maintenance'' language in section 110(a)(2)(D) requires an upwind state to eliminate all emissions that may have some impact on an area in a downwind state that is (or once was) in nonattainment and that, therefore, will need (or now needs) to maintain its attainment status. Instead, we believe that CAIR emission reductions are needed beyond 2010 and 2015, in part, to prevent upwind states from significantly interfering with maintenance in other states because our analysis shows it is likely that, in the absence of the CAIR, a current or projected attainment area will revert to nonattainment due to continued emissions growth or other relevant factors. We are not taking the position that CAIR controls are automatically justified to prevent interference with maintenance in every area initially modeled to be in nonattainment.

We also note that considering the emission controls needed for maintenance, along with the controls needed to reach attainment in the first place, is consistent with the goal of promoting a reasonable balance between upwind state controls and local (including all in-state) controls to attain and maintain the NAAQS. As discussed in section IV of this notice, in the ideal world, the states and EPA would have enough information (and powerful enough analytical tools) to allow us to identify a mix of control strategies that would bring every area of the country into attainment at the lowest overall cost to society. Under such an approach, we would evaluate the impact of every emissions source on air quality in all nonattainment areas, the cost of different options for controlling those sources, and the cost-effectiveness of those controls in terms of cost per increment of air quality improvement. Such an approach would obviously make it easier for a state to develop an appropriate set of control requirements for sources located in that state based on (1) the need to bring its own nonattainment areas into attainment and (2) its responsibility under section 110(a)(2)(D) to prevent significant contribution to nonattainment in downwind States and interference with maintenance in those States.

Such an approach would also make it much easier for the Agency to decide on efficiency grounds whether to take action under section 126 (or under section 110(a)(2)(D) if a State failed to meet its obligations under that section) for purposes of either attainment or maintenance of a NAAQS in another State. In the simplest example, we might need to consider a case in which a downwind State with a nonattainment area is seeking reductions from an upwind State based on the claim that emissions from the upwind state are contributing significantly to the nonattainment problem in the downwind State. In such a case, the first question is whether the upwind state should be required to take any action at all, and in the ideal world, it would be simple to answer this question. If emission reductions from sources in the upwind State are more cost-effective than emission reductions in the downwind State—in terms of cost per increment of improvement in air quality in the downwind nonattainment area—then the upwind State would need to take some action to control emissions from sources in that State.[46] On the other hand, if controls on sources in the upwind State are not more cost-effective in terms of cost per increment of improvement in air quality, then the Agency would not take action under sections 126 or 110(a)(2)(D); rather, the downwind State would need to meets its attainment and maintenance needs by controlling sources within its own jurisdiction. Of course, factors other than efficiency, such as equity or practicality, also might affect the decision.

Unfortunately, we do not have adequate information or analytical tools (ideally a detailed linear programming model that fully integrates both control costs and ambient impacts of sources in each State on each of the downwind receptors) to allow us to undertake the analysis described above at this time. However, the Agency believes that CAIR is consistent with this basic approach and will result in upwind States and downwind States sharing appropriate responsibility for attainment and maintenance of the relevant NAAQS, considering efficiency, equity and practical considerations. Under CAIR, the required reductions in upwind States (including those projected to occur after 2015) are highly cost effective, measured in cost-per-ton of emissions reduction, as documented in section IV. This suggests that, regardless of whether the CAIR reductions assist downwind areas in achieving attainment or in subsequently maintaining the relevant NAAQS, the upwind controls will be reasonable in cost relative to a further increment of local controls that, in most cases, will have a substantially higher cost per ton—particularly in areas that need greater local reductions and require reductions from a variety of source types.[47] Thus, we believe that CAIR is consistent with the goal of attaining and maintaining air quality standards in an efficient, as well as equitable, manner.

Another reason for considering both attainment and maintenance needs at this time is EPA's expectation that most nonattainment areas will be able to

[45] As in the NO_X SIP Call rulemaking, EPA interprets the ''interfere with maintenance'' statutory requirement ''much the same as the term 'contribute significantly' '', that is, ''through the same weight-of-evidence approach.'' 63 FR at 57379. Furthermore, we believe the ''interfere with maintenance'' prong may come into play only in circumstances where EPA or the State can reasonably determine or project, based on available data, that an area in a downwind state will achieve attainment, but due to emissions growth or other relevant factors is likely to fall back into nonattainment. *Id.*

[46] This does not mean that the upwind state would be responsible for making all the reductions necessary to bring the downwind State's nonattainment area into attainment; how much would be required of each State is a separate question. Again in the ideal world, we would be able to find the right mix of controls in both states so that attainment would be achieved at the lowest total cost.

[47] Tables describing cost effectiveness of various control measures and programs are provided in section IV. These show that the cost per ton of non-power-sector control options that states might consider for attainment purposes typically is higher than for CAIR controls.

attain the $PM_{2.5}$ and 8-hour ozone standards within the time periods provided under the statute. Considering both types of downwind needs shows that there is a strong basis for CAIR's requirements despite the potential for most receptor areas to attain before all the emission reductions required by CAIR are achieved.

2. By Design, the CAIR Cap and Trade Program Will Achieve Significant Emissions Reductions Prior to the Cap Deadlines

The EPA notes that Phase I of CAIR is the initial step on the slope of emissions reduction (*i.e.*, the ''glide path'') leading to the final control levels. Because of the incentive to make early emission reductions that the cap and trade program provides, reductions will begin early and will continue to increase through Phases I and II. Therefore, all the required Phase II emission reductions will not take place on January 1, 2015, the effective date of the second phase cap. Rather, these reductions will accrue throughout the implementation period, as the sources install controls and start to test and operate them. The resulting glide path of reductions with CAIR Phase II will provide important reductions to areas coming into attainment over the 2010 to 2014 period.[48]

3. Additional Justification for the SO_2 and NO_X Annual Controls

Our modeling indicates that it is very plausible that a significant number of downwind $PM_{2.5}$ receptors are likely to remain in nonattainment in 2010 and beyond. As noted below (Preamble Table VI–10), the Agency has evaluated a wide range of emission control options and found that the average ambient reduction in $PM_{2.5}$ concentrations achievable through aggressive but feasible local controls is 1.26 $\mu g/m^3$. In the 2010 base case (which does not consider potential local controls or 2010 CAIR controls, but does consider all other emission controls required to be in effect as of that date), nearly half the receptor counties would be in nonattainment by more than this amount. This indicates that nonattainment is of sufficient severity to make it likely that, in the absence of CAIR, many of these areas would need an attainment date extension of at least one year.

Our base case modeling further shows that every upwind state is linked to at least one receptor area projected to have nonattainment of this severity. Tables VI–10 and VI–11. Thus, there is a reasonable likelihood that CAIR controls will be needed from all of the upwind states to prevent significant contribution to these downwind receptors' nonattainment.

Nor is the amount of reduction in excess of what is needed for attainment. We project that even with CAIR controls, almost all of the upwind states in 2010 remain linked with at least one downwind receptor that would not attain by the same substantial margin exceeding the average of aggressive local controls. Tables VI–10 and VI–8. This not only indicates that the 2010 CAIR controls are not excessive, but that local controls will still be necessary for attainment.

In addition, there is potential for residual nonattainment in 2015 in view of the severity of $PM_{2.5}$ levels in some areas, uncertainties about the levels of reductions in $PM_{2.5}$ and precursors that will prove reasonable over the next decade, the potential for up to two 1-year extensions for areas that meet certain air quality levels in the year preceding their attainment date, and historical examples in which areas did not meet their statutory attainment dates for other NAAQS.

With respect to the argument that phase II emission reductions that will be achieved after 2015 are not needed because all receptors will have attained before 2015, we think it likely that some $PM_{2.5}$ nonattainment areas may qualify for 2014 attainment dates and eventually, one-year attainment date extensions, and that there may be residual nonattainment in 2015. We continue to project that nearly half the downwind receptors in the 2015 base case will be in nonattainment by amounts exceeding the average ambient reduction (again, 1.26 $\mu g/m^3$) attributable to local controls we believe would be aggressive but feasible for 2010. Table VI–11. The history of progress in development of emission reduction strategies and technologies indicates that greater local reductions could be achieved by 2015 than in 2010; nonetheless, this potential nonattainment is of sufficient severity to make it plausible that at least some of these areas will need an extension. In such cases, this would eliminate the issue of timing raised by commenters, since CAIR controls would no longer be following attainment dates.

Our modeling further shows that, in the 2015 base case (which does not include CAIR controls), all the upwind states in the CAIR region are linked to areas projected to exceed the standard by at least 2 $\mu g/m^3$. Tables VI–11 and VI–8. Given the reasonable potential for continued nonattainment, it is reasonable to require 2015 CAIR controls from each upwind state to prevent significant contribution to nonattainment.

Moreover, even with 2015 CAIR controls (but not attainment SIP controls), almost all of the upwind states remain linked with at least one downwind receptor that would not attain by at least this same substantial margin (at least 1.26 $\mu g/m^3$). *Id.* This shows that the 2015 CAIR controls are not more than are necessary to attain the NAAQS (and also shows the necessity for local controls in order to attain). Thus, we conclude that the further $PM_{2.5}$ reductions achieved by the second phase cap will likely be needed to assure all relevant areas reach attainment by applicable deadlines.

Even if some of these areas make more progress than we predict, many downwind receptor areas would be likely in 2010 and 2015 to continue to have air quality only marginally better than the standard, and be at risk of returning to nonattainment. Air quality is unlikely to be appreciably cleaner than the standard because many areas will need steep reductions merely to attain, given that we project nonattainment by wide margins (as explained above).

Moreover, we project that without CAIR, $PM_{2.5}$ levels would worsen in 19 downwind receptor counties between 2010 and 2015, reflecting changes in local and upwind emissions. Air Quality Modeling Technical Support Document, November, 2004. This suggests a reasonable likelihood that, without CAIR, these areas would return to nonattainment. See 63 FR at 57379–80 (finding in NO_X SIP Call that upwind emissions interfere with maintenance of 8-hour ozone standard under section 110(a)(2)(D)(i) where increases in emissions of ozone precursors are projected due to growth in emissions generating activity, resulting in receptors no longer attaining the standard). These downwind receptors link to all but two of the upwind states, and the remaining two upwind states are linked to receptors where projected $PM_{2.5}$ levels between 2010 and 2015 improve only slightly, leaving their air quality only marginally in attainment. Response to Comments, section III.C. In light of documented year-to-year variations in $PM_{2.5}$ levels, these receptors would have a reasonable probability of returning to nonattainment in the absence of CAIR.

Emissions trends after 2015 give rise to further maintenance concerns. Between 2015 and 2020, emissions of

[48] A similar glide path will occur prior to the effective date of the Phase I SO_2 cap because this cap will complement and extend the cap that currently exists under the Acid Rain program.

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$PM_{2.5}$ and certain precursors are projected to rise. We do not have air quality modeling for 2020. However, for $PM_{2.5}$ and every precursor, the 2015–2020 emission trend is less favorable than the 2010–2015 emission trend. Given the $PM_{2.5}$ increases our air quality modeling found for 19 counties between 2010 and 2015, the emission trends suggest greater maintenance concerns in the 2015–2020 period than during the 2010–2015 period. See Response to Comments section III.C.

Accordingly, we believe that given these projected trends, and the likelihood of only borderline attainment, CAIR controls from every upwind state in the CAIR region are needed to prevent interference with maintenance of the $PM_{2.5}$ standard. The projected upwards pressure on $PM_{2.5}$ concentrations in most receptor areas indicates that the amount of upwind reductions is not more than necessary to prevent interference with maintenance of the standards, again given the likelihood of initial attainment by narrow margins.

4. Additional Justification for Ozone NO_X Requirements

We believe that most 8-hour ozone areas will be able to attain by their attainment deadlines through existing measures, 2009 CAIR NO_X reductions, and additional local measures. However, we also believe that a limited number of downwind receptor areas will remain in nonattainment with the ozone standard after 2010. This is due to the severity of projected ozone levels in certain areas, uncertainties about the levels of emissions reductions in that will prove reasonable over the next decade, and historical difficulties with attaining the 1-hour ozone standard.

For ozone, the historic difficulties that many areas, particularly large urban areas, have experienced in attaining the ozone NAAQS raises the possibility that some areas may not attain by their attainment dates, and may request a voluntary bump up to a higher classification pursuant to section 181(b)(2) to gain an extension, or may fail to attain by the attainment date and be bumped up under section 181(b)(2). These authorities were used in the course of implementing the 1-hour ozone NAAQS.

Our base case modeling (without CAIR, and without state controls implementing the 8-hour standard) projects geographically widespread nonattainment with the 8-hour ozone NAAQS in 2015. Tables VI–12 and VI–13. Five counties that link to 14 upwind states have projected ozone levels that exceed the 8-hour standard by 6 ppb or more, and 20 upwind states are linked to counties projected to exceed the 8-hour standard by more than 4 ppb. These two sets of linkages show that under a scenario in which several of the receptors with the highest ozone levels did not attain, CAIR reductions would be justified to prevent significant contributions from many of the upwind states in the CAIR ozone region.

The fact that receptors show significant nonattainment even after implementation of the phase II CAIR reductions, as shown in Table VI–13, indicates that these reductions would not be more than necessary to prevent significant contribution to nonattainment in residual areas. Even if all ozone nonattainment areas in the CAIR region could achieve reductions sufficient to meet the level of the 8-hour ozone standard in 2009 [49] based on local controls, 2009 CAIR NO_X reductions, and existing programs, we believe that numerous downwind receptor areas would remain close enough to the standard to be at risk of falling back into nonattainment for the reasons discussed below. These receptor areas are linked to all states in the CAIR ozone region.

First, it is highly unlikely that the receptor areas will be able to attain by a wide margin. This is primarily because many of those areas will need substantial emissions reductions merely to attain. This is supported by modeling showing that in the 2010 base case, 30 percent of the receptors are projected to be in nonattainment by the wide margin of 6 ppb or more, indicating the steep emissions reductions necessary just to come into attainment. Table VI–12. We recognize that, unlike the trend in key PM receptor areas, our modeling projects that the ozone levels in ozone receptor areas will improve somewhat between 2010 and 2015 due chiefly to downward trends in NO_X emissions projected under existing requirements. Nonetheless, as shown in detail in the Response to Comments, the projected improvements in ozone levels in the receptor areas are less (often considerably less) than historic variability in monitored 8-hour ozone design values from one three year period to the next.[50] We believe this variability is mostly attributable to changing weather conditions (which significantly affect the rate at which ozone is formed in the atmosphere and movement of ozone after it is formed), rather than variability in the emissions inventory. Thus, absent the second phase CAIR cap, these receptors remain vulnerable to falling back into nonattainment. The receptors for which this is the case link to each of the upwind States in the ozone CAIR region.

IV. What Amounts of SO_2 and NO_X Emissions Did EPA Determine Should Be Reduced?

In today's rule, EPA requires annual SO_2 and NO_X emissions reductions and ozone-season NO_X emissions reductions to eliminate the amount of emissions that contribute significantly to nonattainment of the NAAQS for $PM_{2.5}$ and ozone. The NO_X reductions are phased in beginning in 2009, the SO_2 reductions beginning in 2010, and both caps are lowered in 2015. In this section of the preamble, EPA explains its analysis of the cost portion of the contribute-significantly test, which determines the amount of required emissions reductions. The cost portion requires analysis of whether the control program under review is highly cost effective, and other factors that are discussed below in section IV.A.

In section IV.A of today's preamble, EPA explains its methodology for determining the amounts of SO_2 and NO_X emissions that must be eliminated for compliance with the CAIR. Section IV.A is divided into IV.A.1, IV.A.2, IV.A.3, and IV.A.4. In IV.A.1, EPA explains the methodology that the Agency used to model control costs for evaluation of cost effectiveness. In IV.A.2, EPA describes the methodology that was proposed in the NPR for determining the amounts of emissions that must be eliminated, including an overview of the proposed methodology, a description of the NO_X SIP Call regulatory history in relation to the proposed methodology, and a description of EPA's proposed criteria for determining emission reduction requirements. Section IV.A.3 summarizes some comments received regarding the proposed methodology. Section IV.A.4 describes EPA's evaluation of highly cost-effective SO_2 and NO_X emissions reductions based on controlling EGUs.

Section IV.A.4 is further divided into IV.A.4.a and IV.A.4.b, which address

[49] Attainment deadlines for moderate ozone areas are to be no later than June 2010; an approvable attainment plan must demonstrate the reductions needed for attainment will be achieved by the ozone season in the preceding year.

[50] We recognize that in the absence of substantial evidence, variability alone would not be a sufficient basis for applying the ''interfere with maintenance'' prong of section 110(a)(2)(D). Here, however, where there is a substantial body of historical data documenting the variability in ozone concentrations, we believe it is appropriate to consider variability in determining whether emission reductions from upwind states are necessary to prevent interference with maintenance of the ozone standard in downwind states.

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SO_2 and NO_X emission reduction requirements, respectively. Section IV.A.4.a describes EPA's evaluation of highly cost-effective SO_2 reduction requirements, beginning with a summary of the proposal and then describing today's final determination. In IV.A.4.b., EPA describes its evaluation of highly cost-effective NO_X reduction requirements, also beginning with a summary of the proposal and then describing today's final determination. Section IV.A.4.b first addresses annual NO_X reductions, and then addresses ozone season NO_X reductions. The final regionwide CAIR SO_2 and NO_X control levels are provided within section IV.A, while a more detailed description of today's final emission reduction requirements is presented in section IV.D.

In section IV.B of today's preamble, EPA discusses other (non-EGU) sources that the Agency considered in developing today's rule.

Section IV.C of today's preamble explains the schedule for implementing today's SO_2 and NO_X emissions reductions requirements. This section begins with an overview of the schedule (see section IV.C.1), then provides a detailed discussion of the engineering factors that affect timing for control retrofits (section IV.C.2). Within IV.C.2, EPA first describes the NPR discussion of engineering factors including the availability of boilermaker labor as a limitation (IV.C.2.a), then presents some comments received (IV.C.2.b) and EPA's responses (IV.C.2.c). In section IV.C.3, EPA discusses the financial stability of the power sector in relation to the schedule for the CAIR.

Section IV.D of today's preamble provides a detailed description of the final CAIR emission reduction requirements. Regionwide SO_2 and NO_X control levels, projected base case emissions and emissions after the CAIR, and projected emissions reductions are presented. Section IV.D begins with a description of the criteria used to determine final control requirements and provides the details of the final requirements.

A. What Methodology Did EPA Use To Determine the Amounts of SO_2 and NO_X Emissions That Must Be Eliminated?

1. The EPA's Cost Modeling Methodology

The EPA conducted analysis using the Integrated Planning Model (IPM) that indicates that its CAIR SO_2 and NO_X reduction requirements are highly cost effective. Cost effectiveness is one portion of the contribute-significantly test. The EPA uses the IPM to examine costs and, more broadly, analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous States and the District of Columbia. The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. The EPA used the IPM to evaluate the cost and emissions impacts of the policies required by today's action to limit annual emissions of SO_2 and NO_X and ozone season emissions of NO_X from the electric power sector (on the assumption that all affected States choose to implement reductions by controlling EGUs using the model cap and trade rule).

The EPA conducted analyses for the final CAIR using the 2004 update of the IPM, version 2.1.9. Documentation describing the 2004 update is in the CAIR docket and on EPA's Web site. Some highlights of the 2004 update include: Updated inventory of electric generating units (EGUs) and installed pollution control equipment; updated State emission regulations; updated coal choices available to generating units; updated natural gas supply curves; updated SCR and SNCR cost assumptions; updated assumptions on performance of NO_X combustion controls; updated title IV SO_2 bank assumptions; updated heat rates and SO_2 and NO_X emission rates; and, updated repowering costs.

The National Electric Energy Data System (NEEDS) contains the generation unit records used to construct model plants that represent existing and planned/committed units in EPA modeling applications of the IPM. The NEEDS includes basic geographic, operating, air emissions, and other data on all the generation units that are represented by model plants in EPA's v.2.1.9 update of the IPM.

The IPM uses model run years to represent the full planning horizon being modeled. That is, several years in the planning horizon are mapped into a representative model run year, enabling the IPM to perform multiple-year analyses while keeping the model size manageable. Although the IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. In EPA's v.2.1.9 update of the IPM, the years 2008 through 2012 are mapped to run year 2010, and the years 2013 through 2017 are mapped to run year 2015.[51] Model outputs for 2009 and 2010 are from the 2010 run year. Model outputs for 2015 are from the 2015 run year.

The EPA used the IPM to conduct the cost-effectiveness analysis for the emissions control program required by today's action. The model was used to project the incremental electric generation production costs that result from the CAIR program. These estimates are used as the basis for EPA's estimate of average cost and marginal cost of emissions reductions on a per ton basis. The model was also used to project the marginal cost of several State programs that EPA considers as part of its base case.

In modeling the CAIR with the IPM, EPA assumes interstate emissions trading. While EPA is not requiring States to participate in an interstate trading program for EGUs, we believe it is reasonable to evaluate control costs assuming States choose to participate in such a program since that will result in less expensive reductions. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with generating capacity greater than 25 MW.

The EPA's IPM modeling accounts for the use of the existing title IV bank of SO_2 allowances. The projected EGU SO_2 emissions in 2010 and 2015 are above the cap levels, because of the use of the title IV bank. The annual SO_2 emissions reductions that are achieved in 2010 and 2015 are based on the caps that EPA determined to be highly cost effective, including the existence of the title IV bank.

The final CAIR requires annual SO_2 and NO_X reductions in 23 States and the District of Columbia, and also requires ozone season NO_X reductions in 25 States and the District of Columbia. Many of the CAIR States are affected by both the annual SO_2 and NO_X reduction requirements and the ozone season NO_X requirements.

The EPA initially conducted IPM modeling for today's final action using a control strategy that is similar but not identical to the final CAIR requirements.[52] Many of the analyses for the final CAIR are based on that initial modeling, as explained further below. The control strategy that EPA initially modeled included three additional States (Arkansas, Delaware and New Jersey) within the region required to make annual SO_2 and NO_X reductions. However, these three States are not required to make annual reductions under the final CAIR. (In the ''Proposed Rules'' section of today's **Federal**

[51] An exception was made to the run year mapping for an IPM sensitivity run that examined the impact of a NO_X Compliance Supplement Pool (CSP). In that run the years 2009 through 2012 were mapped to 2010 and 2008 was mapped to 2008.

[52] The EPA began our emissions and economic analyses for the CAIR before the air quality analysis, which affects the States covered by the final rule, was completed

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Register, EPA is publishing a proposal to include Delaware and New Jersey in the CAIR region for annual SO_2 and NO_X reductions.) The addition of these three States made a total of 26 States and the District of Columbia covered by annual SO_2 and NO_X caps for the initial model run. The initial model run also included individual State ozone season NO_X caps for Connecticut and Massachusetts, and did not include ozone season NO_X caps for any other States.

The Agency conducted revised final IPM modeling that reflects the final CAIR control strategy. The final IPM modeling includes regionwide annual SO_2 and NO_X caps on the 23 States and the District of Columbia that are required to make annual reductions, and includes a regionwide ozone season NO_X cap on the 25 States and the District of Columbia that are required to make ozone season reductions. The EPA modeled the final CAIR NO_X strategy as an annual NO_X cap with a nested, separate ozone season NO_X cap.

In this section of today's preamble, the projected CAIR costs and emissions are generally derived from the final IPM run reflecting the final CAIR. However, some of EPA's analyses are based on the initial IPM run, described above, which reflected a similar but not identical control strategy to the final CAIR. Analyses that are presented in this section of the preamble that are based on the initial IPM run include: IPM sensitivity runs that examine the effects of using the Energy Information Administration (EIA) natural gas price and electricity growth assumptions; marginal cost effectiveness curves developed using the Technology Retrofitting Updating Model; estimates of average annual SO_2 and NO_X control costs and average non-ozone season NO_X control costs, and projected control retrofits used in the feasibility analysis. The air quality analysis in section VI of today's preamble and the benefits analysis in section X, as well as the analyses presented in the Regulatory Impact Analysis (RIA), are based on emissions projections from the initial IPM run.

The EPA believes that the differences between the initial IPM run that the Agency used for many of the analyses for the CAIR, and the final IPM run reflecting the final CAIR requirements, have very little impact on projected control costs and emissions. For the two IPM runs, projected marginal costs of CAIR annual NO_X reductions in 2009 and 2015 are identical. In addition, for the two IPM runs, projected marginal costs of CAIR annual SO_2 reductions in 2010 and 2015 are almost identical. Also, the 2009 and 2015 projected annual NO_X emissions in the region encompassing the States that are affected by the final CAIR annual NO_X requirements are virtually identical when compared between the two model runs (difference between projected NO_X emissions is less than 1 percent for 2009 and less than 2 percent for 2015). In addition, the 2010 and 2015 projected annual SO_2 emissions in the region encompassing the States that are affected by the final CAIR annual SO_2 requirements are virtually the same when compared between the two runs (difference between projected SO_2 emissions is less than 1 percent for 2010 and less than 2 percent for 2015). These comparisons confirm EPA's belief that the initial IPM run very closely represents the final CAIR program.

The IPM output files for the model runs used in CAIR analyses are available in the CAIR docket. A Technical Support Document in the CAIR docket entitled ''Modeling of Control Costs, Emissions, and Control Retrofits for Cost Effectiveness and Feasibility Analyses'' further explains the IPM runs used in the analyses for section IV of the preamble.

2. The EPA's Proposed Methodology To Determine Amounts of Emissions That Must be Eliminated

a. Overview of EPA Proposal for the Levels of Reductions and Resulting Caps, and Their Timing

In the NPR, the amounts of SO_2 and NO_X emissions reductions that EPA proposed could be cost effectively eliminated in the CAIR region in 2010 and 2015, and the amount of the proposed EGU emissions caps for SO_2 and NO_X that would exist if all affected States achieved those reductions by capping EGU emissions, appear in Tables IV–1 and IV–2, respectively.

TABLE IV–1.—PROJECTED SO_2 AND NO_X EMISSION REDUCTIONS IN THE CAIR REGION IN 2010 AND 2015 FOR THE PROPOSED RULE

[Million Tons] [1]

Pollutant	2010	2015
SO_2	3.6	3.7
NO_X	1.5	1.8

[1] CAIR Notice of Proposed Rulemaking (69 FR 4618, January 30, 2004). The proposed annual SO_2 and NO_X caps covered a 27-State (AL, AR, DE, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MO, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI) plus DC region. In addition, we proposed an ozone-season only cap for Connecticut.

TABLE IV–2.—PROPOSED ANNUAL ELECTRIC GENERATING UNIT SO_2 AND NO_X EMISSIONS CAPS IN THE CAIR REGION

[Million Tons] [1]

Pollutant	2010–2014	2015 and later
SO_2	3.9	2.7
NO_X	1.6	1.3

[1] CAIR Notice of Proposed Rulemaking (69 FR 4618, January 30, 2004). The proposed annual SO_2 and NO_X caps covered a 27-State (AL, AR, DE, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MO, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI) plus DC region. In addition, we proposed an ozone-season only cap for Connecticut.

In the NPR, EPA evaluated the amounts of SO_2 and NO_X emissions in upwind States that contribute significantly to downwind $PM_{2.5}$ nonattainment and the amounts of NO_X emissions in upwind States that contribute significantly to downwind ozone nonattainment. That is, EPA determined the amounts of emissions reductions that must be eliminated to help downwind States achieve attainment, by applying highly cost-effective control measures to EGUs and determining the emissions reductions that would result.

From past experience in examining multi-pollutant emissions trading programs for SO_2 and NO_X, EPA recognized that the air pollution control retrofits that result from a program to achieve highly cost-effective reductions are quite significant and can not be immediately installed. Such retrofits require a large pool of specialized labor resources, in particular, boilermakers, the availability of which will be a major limiting factor in the amount and timing of reductions.

Also, EPA recognized that the regulated industry will need to secure large amounts of capital to meet the control requirements while managing an already large debt load, and is facing other large capital requirements to improve the transmission system. Furthermore, allowing pollution control retrofits to be installed over time enables the industry to take advantage of planned outages at power plants (unplanned outages can lead to lost revenue) and to enable project management to learn from early installations how to deal with some of the engineering challenges that will exist, especially for the smaller units that often present space limitations.

Based on these and other considerations, EPA determined in the NPR that the earliest reasonable deadline for compliance with the final

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highly cost-effective control levels for reducing emissions was 2015 (taking into consideration the existing bank of title IV SO_2 allowances). First, the Agency confirmed that the levels of SO_2 and NO_X emissions it believed were reasonable to set as annual emissions caps for 2015 lead to highly cost-effective controls for the CAIR region.

Once EPA determined the 2015 emissions reductions levels, the Agency determined a proposed first (interim) phase control level that would commence January 1, 2010, the earliest the Agency believed initial pollution controls could be fully operational (in today's final action, the first NO_X control phase commences in 2009 instead of in 2010, as explained in detail in section IV.C). The first phase would be the initial step on the slope of emissions reductions (the glide-path) leading to the final (second) control phase to commence in 2015. The EPA determined the first phase based on the feasibility of installing the necessary emission control retrofits, as described in section IV.C.

Although EPA's primary cost-effectiveness determination is for the 2015 emissions reductions levels, the Agency also evaluated the cost effectiveness of the first phase control levels to ensure that they were also highly cost effective. Throughout this preamble section, EPA reports both the 2015 and 2010 (and 2009 for NO_X) cost-effectiveness results, although the first phase levels were determined based on feasibility rather than cost effectiveness. The 2015 emissions reductions include the 2010 (and 2009 for NO_X) emissions reductions as a subset of the more stringent requirements that EPA is imposing in the second phase.

b. Regulatory History: NO_X SIP Call

In the NPR, EPA generally followed the statutory interpretation and approach under CAA section 110(a)(2)(D) developed in the NO_X SIP Call rulemaking. Under this interpretation, the emissions in each upwind State that contribute significantly to nonattainment are identified as being those emissions that can be eliminated through highly cost-effective controls.

In the NO_X SIP Call, EPA relied primarily on the application of highly cost-effective controls in determining the amount of emissions that the affected States were required to eliminate. Specifically, EPA developed a reference list of the average cost effectiveness of recently promulgated or proposed controls, and compared the cost effectiveness of those controls to the cost effectiveness of the NO_X SIP Call controls under consideration. In addition, EPA considered several other factors, including the fact that downwind nonattainment areas had already implemented ozone controls but upwind areas generally had not, the fact that some otherwise required local controls would be less cost-effective than the regional controls, and the overall ambient effects of the reductions required in the NO_X SIP Call (63 FR 57399–57403; October 27, 1998).

i. Highly Cost-Effective Controls

In the NO_X SIP Call, EPA presented control costs in 1990 dollars (1990$). For the electric power industry, these expenditures were the increase in annual electric generation production costs in the control region that result from the rule. In the CAIR NPR, SNPR, and today's final action, EPA presents the same type of electric generation as well as other costs in 1999$, and rounds all values related to the cost per ton of air emissions controls to the nearest 100 dollars.

In the NO_X SIP Call, EPA's decision on the amount of required NO_X emissions reductions was that this amount must be computed on the assumption of implementing highly cost-effective controls. The determination of what constituted highly cost effective controls was described as a two-part process: (1) The setting of a dollar-limit upper bound of highly cost-effective emissions reductions; and (2) a determination of what level of control below this upper-bound was appropriate based upon achievability and other factors.

With respect to setting the upper bound of potential highly cost-effective controls, EPA determined this level on the basis of average cost effectiveness (the average cost per ton of pollutant removed). The EPA explained that it relied on average cost effectiveness for two reasons:

> Since EPA's determination for the core group of sources is based on the adoption of a broad-based trading program, average cost effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs. In addition, average cost-effectiveness estimates are readily available for other recently adopted NO_X control measures (63 FR 57399).

At that time, EPA acknowledged that average cost effectiveness did not directly address the fact that certain units might have higher costs relative to the average cost of reduction (*e.g.*, units with lower capacity factors tend to have higher costs):

> [I]ncremental cost effectiveness helps to identify whether a more stringent control option imposes much higher costs relative to the average cost per ton for further control. The use of an average cost effectiveness measure may not fully reveal costly incremental requirements where control options achieve large reductions in emissions (relative to the baseline) (63 FR 57399).

Examination of marginal cost effectiveness—which examines what the cost would be of the next ton of reduction after the defined control level—would fill this gap. However, for the NO_X SIP Call rulemaking, adequate information concerning marginal cost effectiveness was not available.

For the NO_X SIP Call, to determine the average cost effectiveness that should be considered to be highly cost effective, EPA developed a ''reference list'' of NO_X emissions controls that are available and of comparable cost to other recently undertaken or planned NO_X measures. The EPA explained that ''the cost effectiveness of measures that EPA or States have adopted, or proposed to adopt, forms a good reference point for determining which of the available additional NO_X control measures can most easily be implemented by upwind States whose emissions impact downwind nonattainment problems.'' (63 FR 57400). The EPA explained that the measures on the reference list had already been implemented or were planned to be implemented, and therefore could be assumed to be less expensive than other measures to be implemented in the future. The EPA found that the costs of the measures on the reference list approached but were below $2,000 per ton (1990$). The EPA concluded that ''controls with an average cost effectiveness [of] less than $2,000 [1990$, or $2,500 (1999$)] per ton of NO_X removed [should be considered] to be highly cost-effective.'' (63 FR 57400). Notably, the reference costs were taken from the supporting analyses used for the regulatory actions covering the NO_X pollution controls—they are what regulatory decision makers and the public believed were the control costs.

Mindful of this $2,000 limit [1990$, or $2,500 (1999$)], EPA considered a control level that would have resulted in estimated average costs of approximately $1,800 (1990$) per ton. However, EPA concluded that because the corresponding level of controls—nominally a 0.12 lb/mmBtu control level—was not well enough established, EPA was ''not as confident about the robustness'' of the cost estimates. Moreover, EPA expressed concern that its ''level of comfort'' was not as high as

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it would have liked that the nominal 0.12 lb/mmBtu control level ''will not lead to installation of SCR technology at a level and in a manner that will be difficult to implement or result in reliability problems for electric power generation'' (63 FR 57401).

Accordingly, EPA selected the next control level that it had evaluated—a nominal 0.15 lb/mmBtu level—which would result in an average cost of approximately $1,500 [1990$, or $1,900 (1999$)] per ton. The EPA determined that this control level did not present the uncertainty concerns associated with the 0.12 level. The EPA added, in this 1998 rule: ''With a strong need to implement a program by 2003 that is recognized by the States as practical, necessary, and broadly accepted as highly cost-effective, the Agency has decided to base the emissions budgets for EGUs on a 0.15 * * * level.'' (63 FR 57401—57402). The EPA summarized its approach as determining ''the required emission levels * * * based on the application of NO_X controls that achieve the greatest feasible emissions reduction while still falling within a cost-per-ton reduced range that EPA considers to be highly cost-effective.* * *'' (63 FR 57399).

The bulk of the cost for reducing NO_X emissions for EGUs is in the capital investment in the control equipment, which would be the same whether controls are installed for ozone season only, or for annual controls. The increased costs to run the equipment annually instead of only in the ozone season is relatively small. Although the NO_X SIP Call is an ozone season NO_X reduction program, most of the NO_X control costs on the reference list are for annual reductions. If the NO_X SIP Call were an annual program instead of seasonal, its average control costs would be lower, relative to the annual control costs in the reference list.

ii. Other Factors

In the NO_X SIP Call, although considering air quality and cost to be the primary factors for determining significant contribution, EPA identified several other factors that it generally considered. As one factor, EPA reviewed ''overall considerations of fairness related to the control regimes required of the downwind and upwind areas,'' particularly, the fact that the major urban nonattainment areas in the East had implemented controls on virtually all portions of their inventory of ozone precursors, but upwind sources had not implemented reductions intended to reduce their impacts downwind (63 FR 57404).

As another factor, EPA generally considered ''the cost effectiveness of additional local reductions in the * * * ozone nonattainment areas.'' The EPA included in the record information that nationally, on average, additional local measures would cost more than the cost of the upwind controls required under the NO_X SIP Call. This consideration further indicated that the regional controls under the NO_X SIP Call were highly cost effective (63 FR 57404).

In addition, EPA conducted air quality modeling to determine the impact of the controls, and found that they benefitted the downwind areas without being more than necessary for those areas to attain (63 FR 57403—57404).

c. Proposed Criteria for Emissions Reduction Requirements

i. General Criteria

In the CAIR NPR, EPA proposed criteria for determining the appropriate levels of annual emissions reductions for SO_2 and NO_X and ozone-season emissions reductions for NO_X. The EPA stated that it considers a variety of factors in evaluating the source categories from which highly cost-effective reductions may be available and the level of reduction assumed from that sector. These include:

- The availability of information,
- The identification of source categories emitting relatively large amounts of the relevant emissions,
- The performance and applicability of control measures,
- The cost effectiveness of control measures, and
- Engineering and financial factors that affect the availability of control measures (69 FR 4611).

Further, EPA stated that overall, ''We are striving * * * to set up a reasonable balance of regional and local controls to provide a cost-effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone.'' (69 FR 4612)

The EPA has used these types of criteria in a number of efforts to develop regional and national strategies to reduce interstate transport of SO_2 and NO_X. Starting in 1996, EPA performed analysis and engaged in dialogue with power companies, States, environmental groups and other interested groups in the Clean Air Power Initiative (CAPI).[53] In that study of national emission reduction strategies, EPA initially considered an emissions cap based on a 50 percent reduction in SO_2 emissions from title IV levels (*i.e.*, 4.5 million tons nationwide) in 2010. For NO_X, EPA initially looked at ozone season and non-ozone season caps. Commencing in 2000, the ozone season emissions cap would be based on an emission rate of 0.20 lb/mmBtu, and in 2005, the ozone season cap would be reduced to a level based on 0.15 lb/mmBtu (these cap levels would be similar to the phased caps adopted by the Ozone Transport Commission (OTC) States). The non-ozone season cap would be based on the proposed title IV phase II NO_X rule. The EPA also considered other options in the CAPI study, including setting NO_X caps based on emission rates of 0.20 lb/mmBtu and 0.25 lb/mmBtu; setting NO_X caps based on rates of 0.15 lb/mmBtu and 0.20 lb/mmBtu but lowering the SO_2 allowance cap by 60 percent instead of 50 percent; and, keeping a NO_X cap based on a rate of 0.15 lb/mmBtu but lowering the SO_2 allowance cap by 50 percent in 2005 instead of in 2010.

The EPA did a follow-up study in 1999 and discussed those results with various stakeholder groups, as well.[54] That study considered a variety of SO_2 emission caps ranging from a 40 percent reduction from title IV cap levels in 2010 to a 55 percent reduction from title IV cap levels in 2010. The 1999 study did not consider additional reductions in NO_X emissions beyond those required under the NO_X SIP Call.

In the last several years, EPA has performed significant additional analysis in support of the proposed Clear Skies Act.[55] That legislation, proposed in 2002 and 2003, would include nationwide SO_2 caps of 4.5 million tons in 2010 and 3.0 million tons in 2018 (*i.e.*, 50 percent and 67 percent reductions from title IV cap levels). The Clear Skies Act also includes a two-phase, two-zone NO_X emission cap program, with the first phase in 2008 and the second phase in 2018. In the 2003 legislation, the first phase NO_X caps would result in effective NO_X emissions rates of 0.16 lb/mmBtu in the east and 0.20 lb/mmBtu in the west, and the second phase would result in effective emission rates of 0.12 lb/mmBtu in the east and 0.20 lb/mmBtu in the west.

[53] U.S. Environmental Protection Agency, Office of Air and Radiation, EPA's Clean Air Power Initiative, October 1996.

[54] U.S. Environmental Protection Agency, Office of Air and Radiation, Analysis of Emission Reduction Options for the Electric Power Industry, March 1999.

[55] EPA's Clear Skies Act analysis is on the web at: *http://www.epa.gov/air/clearskies/technical.html.*

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ii. Reliance on Average and Marginal Cost Effectiveness

In the CAIR NPR, EPA supported the conclusion that its emissions caps are highly cost effective based upon ''(1) comparison to the average cost effectiveness of other regulatory actions and (2) comparison to the marginal cost effectiveness of other regulatory actions.'' (69 FR 4585). We supplemented these comparisons of cost-effectiveness tables with an auxiliary evaluation of the marginal costs curves, which allowed us to show that the selected control levels would be ''below the point at which there would be significant diminishing returns on the dollars spent for pollution control.'' (69 FR 4614).

Although in the NO_X SIP Call, EPA based the required controls on average cost alone, in today's rule, EPA uses both average and marginal costs, including an evaluation of the marginal cost curves. At the time of the NO_X SIP Call, marginal cost information was not as readily available. Today, such information is available for both SO_2 and NO_X controls, although marginal cost information remains more limited and EPA has had to specifically develop marginal cost estimates for use in this rulemaking.

Marginal costs are a useful measure of cost effectiveness because they indicate how much any additional level of control at the margin will cost relative to other actions that are available. Using both average and marginal control costs, provides a more complete picture of the costs of controls than using average costs alone. Average costs provide a means for a straightforward comparison between the CAIR and other emissions reductions programs for which average costs are generally the only type of costs available. Where marginal cost information is available, it enables EPA to compare the costs of the CAIR at the stringency level being considered to the costs of the last increment of control in other programs. Moreover, evaluation of marginal cost curves allows us to corroborate that the selected level of stringency of the selected program stops short of the point where the returns begin to diminish significantly.

Projected marginal cost information for controlling emissions from EGUs is now available for some State programs, because EPA includes the programs in its base case power sector modeling using the IPM to develop the incremental costs of electricity production for the CAIR. Marginal EGU control costs from State programs modeled using the IPM were compared to projected marginal EGU control costs under the CAIR, as discussed in more detail below.

3. What Are the Most Significant Comments That EPA Received About Its Proposed Methodology for Determining the Amounts of SO_2 and NO_X Emissions That Must Be Eliminated, and What Are EPA's Responses?

Some commenters took issue with EPA's reliance on cost-per-ton-of-emissions-reductions as the metric for determining cost effectiveness. These commenters observed that this metric does not take into account that any given ton of pollutant reduction may have different impacts on ambient concentration and human exposure. Some of these commenters advocated use of a metric based on cost per unit of pollutant concentration reduced. Another stated that EPA should account for cost effectiveness based on geographical location relative to the area of nonattainment.

Still other commenters took a contrasting view. They argued that a metric based on cost-per-ambient-impact might be useful in justifying control cost effectiveness for source categories within an individual nonattainment area as part of an attainment SIP, but not for evaluating costs of controlling long-range transport. These commenters stated that it is impractical to calculate cost effectiveness of control on the basis of cost per unit reduction in ambient concentration. One queried: ''Where would the ambient reduction be measured? 100 miles downwind? 1,500 miles downwind?''

The EPA agrees that optimally, the cost-per-ambient-impact of controls could play a major role in determining upwind control obligations (although equitable considerations and other factors identified in the NO_X SIP Call rulemaking and today's action may also play a role). The EPA recognized the potential importance of this factor during the NO_X SIP Call rulemaking and endeavored to develop technical information to support it. However, in that rulemaking, EPA was not able to develop an approach to quantify, with sufficient accuracy, cost-per-ambient impact because the NO_X SIP Call region was large—covering approximately half of the continental U.S. and including approximately half the States—and many upwind States with different emissions inventories had widely varied impacts on many different nonattainment areas downwind.

This problem—the complexity of the task and the dearth of analytic tools—remains today for both $PM_{2.5}$ and 8-hour ozone regional transport. Not surprisingly, no commenter presented to EPA the analytic tools, which we would expect would consist of a complex, computerized program that could integrate, on a State-by-State basis, both control costs and ambient impacts by each State on each of its downwind receptors under the CAIR control scenario.

In the absence of a scientifically defensible, practicable method for implementing a program design approach based on the cost-per-ambient-impact of emissions reductions, EPA is not able to employ such an approach. However, EPA believes it appropriate to continue to examine ways to develop such an approach for future use.

A few commenters suggested that EPA should use a cost-benefit analysis for determining reduction levels. One noted that cost-benefit analysis can help find the reduction levels that maximize societal net benefit (benefits minus costs), and suggested the Agency should compare the marginal cost of each ton of pollutant reduced to the marginal benefit achieved, as well as compare the total costs to the total benefits. Another stated that an optimal allocation of resources is where the marginal cost equals the marginal benefit, and observed that comparing the average cost to the average benefit of the controls proposed in the CAIR NPR yields an average benefit significantly higher than the average cost. This commenter concluded that EPA should require controls beyond the controls described in the NPR as highly cost effective.

Although EPA strongly agrees that examination of costs and benefits is very useful, in today's rulemaking, EPA does not interpret CAA section 110(a)(2)(D) to base the amount of emissions reductions on benefits other than progress towards attainment of the $PM_{2.5}$ or the 8-hour ozone NAAQS. The EPA's interpretation does, however, use cost effectiveness per ton of pollutant reduced, and we are using that analytic tool for setting SO_2 and NO_X emission reduction requirements. Additionally, EPA has prepared a cost-benefit analysis to inform the Agency and public of the many other important impacts of this rulemaking.

A few commenters suggested that the Agency should set its NO_X and SO_2 reduction requirements based on Best Available Control Technology (BACT) emission rates for EGUs. Although not clearly stated, the commenters appear to suggest BACT level controls for both existing and new units.

The emission reduction requirements that EPA determined are based on the application of highly cost-effective controls that are a step that the Agency is taking at this time to eliminate emissions that contribute significantly to nonattainment of the ozone and fine particle NAAQS. As explained elsewhere, this step is reasonable in light of the current status of implementation for those NAAQS.

Basing emission reduction requirements on a presumption of BACT emission rates across the board would require scrubbers and SCRs on all coal-fired units and SCRs on all gas-fired and oil-fired units. The cost of these controls would vary considerably from source to source, be expensive for many sources, and may cause substantial fuel switching to natural gas and closure of smaller coal-fired units. Having considered this suggestion for deeper regional reductions that would not be as cost effective as the highly cost-effective reductions in today's rule, EPA believes that a more tailored approach, such as the CAIR level control as well as local controls under SIPs (where necessary), is a more reasonable approach to achieving the level of ambient improvement needed for attainment throughout the United States.

4. The EPA's Evaluation of Highly Cost-Effective SO_2 and NO_X Emissions Reductions Based on Controlling EGUs

a. SO_2 Emissions Reductions Requirements

i. CAIR Proposal for SO_2

The NPR focused primarily on determining highly cost-effective amounts of emissions reductions based on, as in the NO_X SIP Call, comparison to reference lists of the cost effectiveness of other regulatory controls. In the NPR, EPA developed reference lists for both the average cost effectiveness and the marginal cost effectiveness of those other controls. These reference lists indicated that the average annual costs per ton of SO_2 removed ranged from $500 to $2,100; and marginal costs of SO_2 removal ranged from $800 to $2,200.

Moreover, EPA further considered the cost effectiveness of alternative stringency levels for this regulatory proposal. That is, EPA examined changes in the marginal cost curve at varying levels of emissions reductions. The EPA determined in the NPR that the ''knee'' in the marginal cost-effectiveness curve—the point at which the marginal cost per ton of SO_2 removed begins to increase at a noticeably higher rate—appears to start above $1,200 per ton (69 FR 4613—4615).

In the NPR, EPA then provided further analysis of a two-phase SO_2 reduction program. The final (second) phase, in 2015, would reduce SO_2 emissions in the CAIR region by the amount that results from making a 65 percent reduction from the title IV Phase II allowance levels (taking into consideration the existing bank of title IV SO_2 allowances). The first phase, in 2010, would reduce SO_2 emissions in the CAIR region by a lesser amount, *i.e.*, a 50 percent reduction from title IV Phase II allowance levels (again, taking into consideration the banked title IV SO_2 allowances). The EPA developed this target SO_2 control level for further evaluation because, based on all of the earlier work performed on multi-pollutant power plant reduction programs and general consideration, with technical support, of overall emissions reductions, costs to industry and the general public, ambient improvement, and consistency with the emerging $PM_{2.5}$ implementation program, we believed it would meet the criteria set forth above.

Then, EPA conducted cost analyses of this control level using the IPM as well as additional analysis of the implications of this control level to determine if it did indeed meet those criteria. The IPM analysis considered the increase in annual electric generation production costs in the CAIR region that result from the rule. The EPA evaluated the cost effectiveness of the final phase (2015) cap to determine if it is highly cost effective; and, we also evaluated the cost effectiveness of the 2010 cap. The EPA used the IPM to estimate cost effectiveness of the CAIR in the future. The IPM incorporates projections of future electricity demand, and thus heat input growth. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with capacity greater than 25 MW. A description of the IPM is included elsewhere in this preamble, and a detailed model documentation is in the docket.

The SO_2 annual control costs that were presented in the CAIR NPR were average costs of $700 per ton and $800 per ton for years 2010 and 2015, respectively, and marginal costs of $700 per ton and $1,000 per ton for years 2010 and 2015. In addition, the NPR included the results of sensitivity analyses that examined costs of the proposed SO_2 controls based on the Energy Information Administration's projections for electricity growth and natural gas prices. These sensitivity analyses showed marginal SO_2 control costs of $900 per ton and $1,100 per ton for years 2010 and 2015, respectively. The EPA proposed to consider the SO_2 emissions reductions proposed in the NPR as highly cost effective because they were consistent with the lower end of the reference list range of cost per ton of SO_2 reduction for controls on both an average and a marginal cost basis (69 FR 4613—4615).

ii. Analysis of SO_2 Emission Reduction Requirements for Today's Final Rule

(I) Reference Lists of Cost-Effective SO_2 Controls

For today's action, EPA updated the reference list of controls included in the NPR of the average and marginal costs per ton of recent SO_2 control actions. The EPA systematically developed a list of cost information from both recent actions and proposed actions. The EPA compiled cost information for actions taken by the Agency, and examined the public comments submitted after the NPR was published, to identify all available control cost information to provide the updated reference list for today's preamble. The updated reference list includes both average and marginal costs of control, to which EPA compares the CAIR control costs, and the list represents what regulatory decision makers and/or the public believes are the control costs.[56]

Table IV–3 provides average costs of SO_2 controls. This table includes average costs for recent BACT permitting decisions for SO_2. Under EPA's New Source Review (NSR) program, if a company is planning to build a new plant or modify an existing plant such that a significant net increase in emissions will occur, the company must obtain a NSR permit that addresses controls for air emissions. BACT is the type of control required by the NSR program for existing sources in attainment areas. The BACT decisions are determined on a case-by-case basis, usually by State or local permitting agencies, and reflect consideration of average and incremental cost effectiveness. These decisions are relevant for EPA's reference list of average costs of SO_2 controls, because they represent cost-effective controls that have been demonstrated.

[56] The updated reference list includes estimated average costs for SO_2 reductions from EGUs under best available retrofit technology (BART) requirements. The BART rule was proposed and has not been finalized (69 FR 25184; May 5, 2004).

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TABLE IV–3.—AVERAGE COSTS PER TON OF ANNUAL SO_2 CONTROLS

SO_2 control action	Average cost per ton
Best Available Control Technology (BACT) Determinations	[1] $400–$2,100
Nonroad Diesel Engines and Fuel	[2] $800
Proposed Best Available Retrofit Technology (BART) for Electric Power Sector	[3] $2,600–$3,400

[1] These numbers reflect a range of cost-effectiveness data entered into EPA's RACT/BACT/LAER Clearinghouse (RBLC) for add-on SO_2 controls (*www.epa.gov/ttn/catc/*). We identified actions in the data base for large, utility-scale, coal-fired boiler units for which cost effectiveness data were reported. The range of costs shown here is for boilers ranging from 30 MW to an estimated 790 MW (we used a conversion factor of 10 mmBtu/hr = 1 MW for units for which size was reported in mmBtu/hr). Emission limits for these actions ranged from 0.10 lb/mmBtu to 0.27 lb/mmBtu. Add-on controls reported for these units are dry or wet scrubbers (in one case with added alkali and in one case with a baghouse). Where the dollar-year was not reported we assumed 1999 dollars. The cost range presented in the NPR was $500–$2,100–today's range includes additional BACT costs that were entered into the clearinghouse after the NPR was published.

[2] Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule (69 FR 39131; June 29, 2004). The value in this table represents the long-term cost per ton of emissions reduced from the total fuel and engine program (cost per ton of emissions reduced in the year 2030). 1999$ per ton.

[3] The EPA IPM modeling 2004, available in the docket. The EPA modeled the Regional Haze Requirements as source specific limits (90 percent SO_2 reduction or 0.1 lb/mmBtu rate; except the five state WRAP region for which we did not model SO_2 controls beyond what is done for the WRAP cap in the base case modeling). Estimated average costs based on this modeling are $2,600 per ton in 2015 and $3,400 per ton in 2020. 1999$ per ton.

Table IV–4 provides the marginal cost per ton of recent State and regional decisions for annual SO_2 controls.

TABLE IV–4.—MARGINAL COSTS PER TON OF ANNUAL SO_2 CONTROLS

SO_2 control action	Marginal cost per ton
New Hampshire Rule	[1] $600
WRAP Regional SO_2 Trading Program	[2] $1,100–$2,200

[1] The EPA IPM base case modeling August 2004, available in the docket. (1999$ per ton). We modeled New Hampshire's State Bill ENV-A2900, which caps SO_2 emissions at all existing fossil steam units.

[2] "An Assessment of Critical Mass for the Regional SO_2 Trading Program," prepared for Western Regional Air Partnership Market Trading Forum by ICF Consulting Group, September 27, 2002, available in the docket. This analysis looked at the implications of one or more States choosing to opt-out of the WRAP regional SO_2 trading program. (1999$ per ton)

(II) Cost Effectiveness of the CAIR Annual SO_2 Reductions

In the NPR, EPA evaluated an annual SO_2 control strategy based on a specified level of emissions reductions from EGUs. Available information indicated that emissions reductions from this industry would be the most cost effective. (As noted elsewhere, EPA considered control strategies for other source categories, but concluded that they would not qualify as highly cost-effective controls.) Of course, under today's rule, although EPA calculates the amount of emissions reductions States must achieve by evaluation of the EGU control strategy, States remain free to achieve those reductions by implementing controls on any sources they wish.

For today's action, EPA updated the predicted annual SO_2 control costs included in the NPR. The EPA analyzed the costs of the CAIR using an updated version of the IPM (documentation for the IPM update is in the docket). Further, EPA modified the modeling to match the final CAIR strategy (see section IV.A.1 for a description of EPA's CAIR IPM modeling).

The EPA also updated its analysis of the sensitivity of the marginal cost results to assumptions of higher electric growth and natural gas prices than we used in the base case. These sensitivity analyses were based on the Energy Information Administration's Annual Energy Outlook for 2004.[57]

In determining whether our control strategy is highly cost effective, EPA believes it is important to account for the variable levels of cost effectiveness that these sensitivity analyses indicate may occur if electricity demand or natural gas prices are appreciably higher than assumed in the IPM. Those two factors are key determinants of control costs and, over the relatively long implementation period provided under today's action, a meaningful degree of risk arises that these factors may well vary to the extent indicated by the sensitivity analyses. As a result, EPA wanted to examine the marginal costs that would occur under the scenarios modeled in the sensitivity analyses to see how they differed from the costs using EPA's assumptions.

Table IV–5 provides the average and marginal costs of annual SO_2 reductions under the CAIR for 2010 and 2015. (When presenting estimated CAIR control costs in section IV of this preamble, EPA uses "Main Case" to indicate the primary CAIR IPM analyses, as differentiated from other IPM analyses such as sensitivity runs used to examine the impacts of varying assumptions about natural gas price and electric growth.)

TABLE IV–5.—ESTIMATED COSTS PER TONS OF SO_2 CONTROLLED UNDER CAIR, CAP LEVELS BEGINNING IN 2010 AND 2015 [1]

Type of cost effectiveness	2010	2015
Average Cost—Main Case	$500	$700
Marginal Cost—Main Case	700	1,000

[57] The EPA used the difference between EIA's estimates for well-head natural gas prices and minemouth coal prices to determine the sensitivity of IPM's results to higher natural gas prices. The EPA describes this sensitivity analysis as "EIA natural gas prices". For electric demand, we replaced EPA's assumed annual growth of 1.6 percent with EIA's projection of annual growth of 1.8 percent.

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TABLE IV–5.—ESTIMATED COSTS PER TONS OF SO_2 CONTROLLED UNDER CAIR, CAP LEVELS BEGINNING IN 2010 AND 2015 [1]—Continued

Type of cost effectiveness	2010	2015
Sensitivity Analysis: Marginal Cost Using EIA Electric Growth and Natural Gas Prices	800	1,200

[1] The EPA IPM modeling 2004, available in the docket. $1999 per ton.

These estimated SO_2 control costs under the CAIR reflect annual EGU SO_2 caps of 3.6 million tons in 2010 and 2.5 million tons in 2015 within the CAIR region. Based on IPM modeling, EPA projects that SO_2 emissions in the CAIR region will be about 5.1 million tons in 2010 and 4.0 million tons in 2015. The projected emissions are above the cap levels because of the use of the existing title IV bank of SO_2 allowances. Average costs shown for 2015 are an estimate of the average cost per ton to achieve the total difference in projected emissions between the base case conditions and the CAIR in the year 2015 (the 2015 average costs are not based on the increment in reductions between 2010 and 2015). (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided below in today's preamble.)

(III) SO_2 Cost Comparison for CAIR Requirements

The EPA believes that if an SO_2 control strategy has a cost effectiveness that is at the low end of the updated reference tables, the approach should be considered to be highly cost effective. The costs in the reference range should be considered to be cost effective because they represent actions that have already been taken to reduce emissions. In deciding to require these actions, policymakers at the local, State and Federal levels have determined them to be cost-effective reductions to limit or reduce emissions. Thus, costs at the bottom of the range must necessarily be considered highly cost effective.

Today's action requires SO_2 emissions reductions (or an EGU emissions cap) in 2015. The EPA has determined that those emissions reductions are highly cost effective. In addition, today's action requires that some of those SO_2 emissions reductions (or a higher EGU emissions cap) be implemented by 2010. The EPA has examined the cost effectiveness of implementing those earlier emissions reductions (or cap) by 2010, and determined that they are also highly cost effective.

The cost of the SO_2 reductions required under today's action—if the States choose to implement those reductions through EGUs, for which the most cost-effective reductions are available—on average and at the margin, are at the lower end of the range of cost effectiveness of other, recent SO_2 control requirements.[58] This is true for our analysis of both the costs EPA generally expects as well as the somewhat higher costs that would result from higher than expected electricity demand and natural gas prices, as indicated in the sensitivity analyses that EPA has done.

Specifically, the average cost effectiveness of the SO_2 requirements is $700 per ton removed in 2015. This amount falls toward the low end of the reference range of average costs per ton removed of $400 to $3,400. Similarly, the marginal cost effectiveness of the SO_2 requirements ranges from $1,000 to $1,200 for 2015 (with the higher end of the range based on the sensitivity analyses). These amounts fall toward the lower end of the reference range of marginal cost per ton removed of $600 to $2,200.

The EPA believes that selecting as highly cost-effective amounts toward the lower end of our average and marginal cost ranges for SO_2 and NO_X control is appropriate because today's rulemaking is an early step in the process of addressing $PM_{2.5}$ and 8-hour ozone nonattainment and maintenance requirements. The CAA requires States to submit section 110(a)(2)(D) plans to address interstate transport, and overall attainment plans to ensure the NAAQS are met in local areas. By taking the early step of finalizing the CAIR, we are requiring a very substantial air emission reduction that addresses interstate transport of $PM_{2.5}$ as well as a further reduction in interstate transport of ozone beyond that required by the NO_X SIP Call Rule. Much of the air quality improvement resulting from reduced transport is likely to occur through broad and deep emissions reductions from the electric power sector, which has been a major part of the transport problem. Other air quality benefits will occur as the result of Federal mobile source regulations for new sources, which cover passenger vehicles and light trucks, heavy-duty trucks and buses, and non-road diesel equipment.

Against this backdrop of Federal actions that lower air emissions (as well as some substantial State control programs), States will develop plans designed to achieve the standards in their local nonattainment areas. The EPA has not yet promulgated rules interpreting the CAA's requirements for SIPs for $PM_{2.5}$ and ozone nonattainment areas,[59] nor have States developed plans to demonstrate attainment. As a result, there are significant uncertainties regarding potential reductions and control costs associated with State plans. We believe that some areas are likely to attain the standards in the near term through early CAIR reductions and local controls that have costs per ton similar to the levels we have determined to be highly cost effective. We expect that other areas with higher $PM_{2.5}$ or ozone levels will determine through the attainment planning process that they need greater emissions reductions, at higher costs per ton, to reach attainment within the CAA's timeframes. For those areas, States will need to assess targeted measures for achieving local attainment in a cost-effective (but not necessarily highly cost-effective) manner, in combination with the CAIR's significant reductions. Given the uncertainties that exist at this early stage of the implementation process, EPA believes this rule is a rational approach to determining the highly cost-effective reductions in $PM_{2.5}$ and ozone precursors that should be required for interstate transport purposes.

As discussed above, the Agency believes this approach is consistent with our action in the NO_X SIP Call. While the cost level selected for the NO_X SIP Call was not at the low end of the reference range of costs, if the NO_X SIP Call costs were for annual rather than seasonal controls they would have been lower relative to the annual control costs on the list. This would make the relationship between the cost of the NO_X SIP Call and the reference costs used in that rulemaking, more similar to relative costs of CAIR compared to its reference lists. Also, significant local controls for meeting the 1-hour ozone standard had already been adopted in many areas.

Although EPA's primary cost-effectiveness determination is for the 2015 emissions reductions levels, the Agency also evaluated the cost effectiveness of the interim phase control levels to ensure that they were also highly cost effective. For the SO_2 requirements for 2010, the average cost effectiveness is $500 per ton removed, and the marginal cost effectiveness

[58] The updated reference list of average SO_2 control costs includes estimated average EGU costs under BART. The BART rule has been proposed but not finalized (69 FR 25184; May 5, 2004).

[59] EPA did promulgate Phase I of the ozone implementation rule in April 2004 (69 FR 23951; April 30, 2004) but has not issued Phase II of the rule, which will interpret CAA requirements relating to local controls (*e.g.,* RACT, RACM, RFP).

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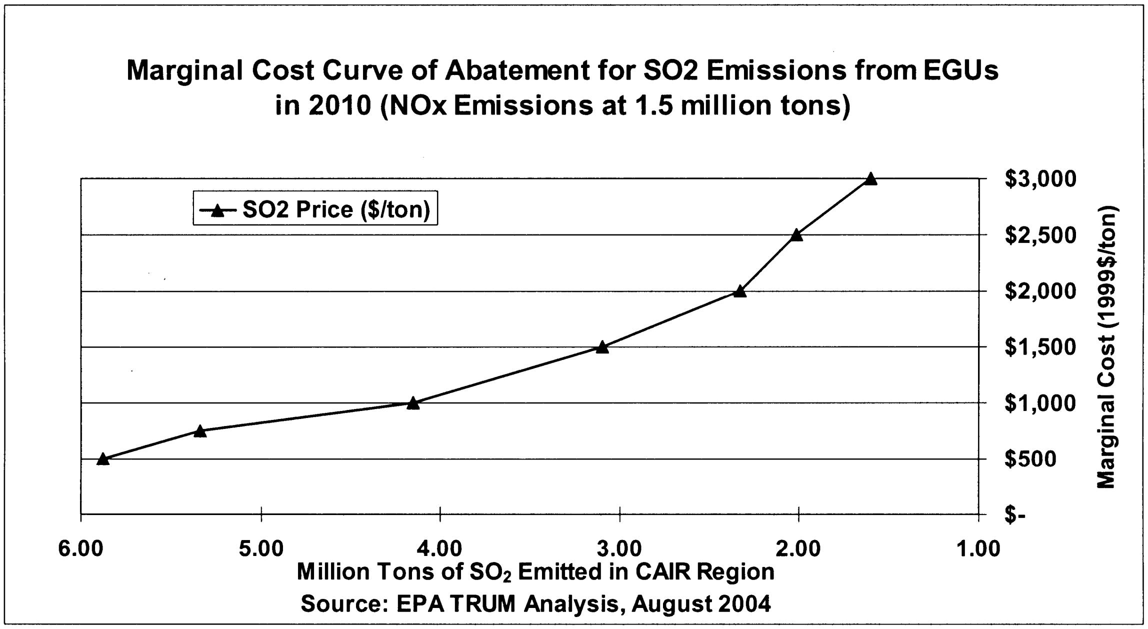
ranges from $700 to $800. The 2010 costs indicate that the interim phase CAIR reductions are also highly cost-effective.

(IV) Cost Effectiveness: Marginal Cost Curves for SO_2 Control

As noted above, the Agency also considered another factor to corroborate its conclusion concerning the cost effectiveness of the selected levels of control:

Figure IV-1.



The cost effectiveness of alternative stringency levels for today's action. Specifically, EPA examined changes in the marginal cost curve at varying levels of emissions reductions for EGUs. Figure IV–1 shows that the ''knee'' in the 2010 marginal cost-effectiveness curve—the point where the cost of controlling a ton of SO_2 from EGUs is increasing at a noticeably higher rate—appears to occur at about $2,000 per ton of SO_2. Figure IV–2 shows that the ''knee'' in the 2015 marginal cost-effectiveness curve also appears to occur at about $2,000 per ton of SO_2. (As discussed above, the projected marginal costs of SO_2 reductions for the CAIR are $700 per ton in 2010 and $1,000 per ton in 2015.) The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on the IPM, for this analysis. (The EPA based these marginal SO_2 cost-effectiveness curves on the electric growth and natural gas price assumptions in the main CAIR IPM modeling run. Marginal cost effectiveness curves based on other electric growth and natural gas price assumptions would look different, therefore it would not be appropriate to compare the curves here to the marginal costs based on the IPM modeling sensitivity run that used EIA assumptions.) These results make clear that this rule is very cost effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[60]

[60] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. It should be noted that similar analysis for other source categories may yield different curves.

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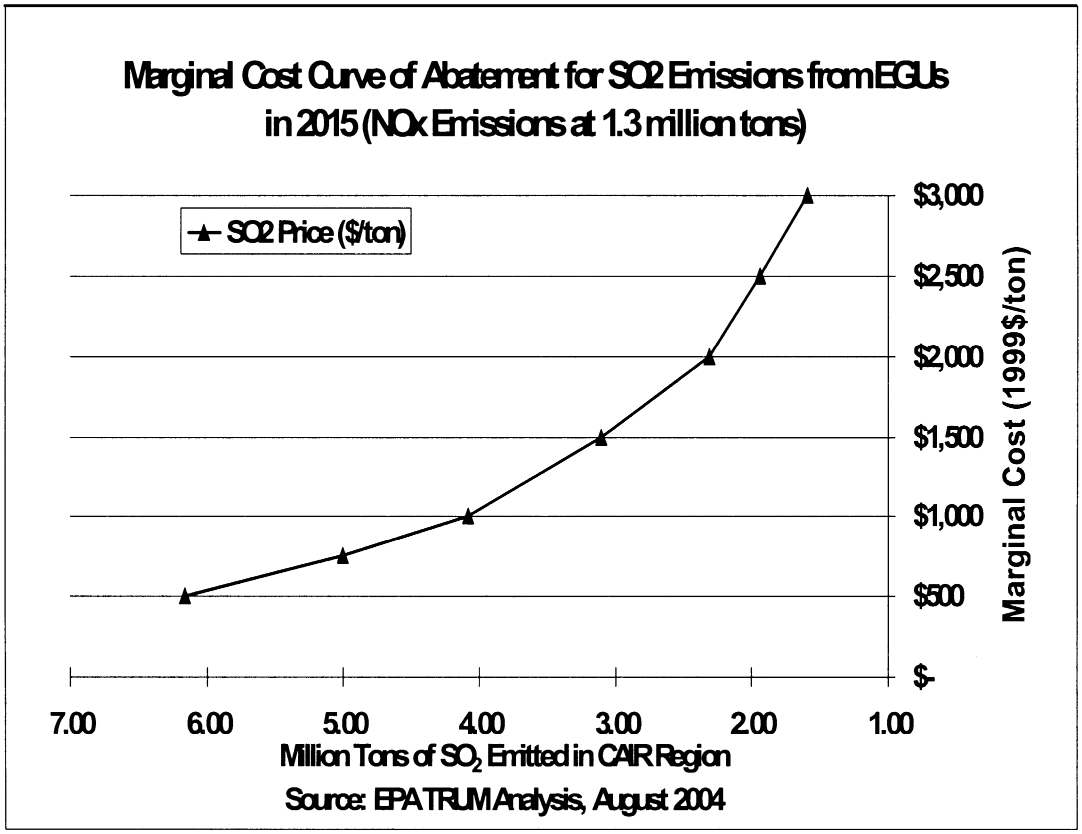
Figure IV -2.



b. NO_X Emissions Reductions Requirements

i. The CAIR Proposal for NO_X and Subsequent Analyses for Regionwide Annual and Ozone Season NO_X Control Levels

In this section, EPA describes its proposed method for determining regionwide NO_X control levels and the method used for the final CAIR.

In the CAIR NPR, EPA updated the reference list included in the NO_X SIP Call for the average annual cost effectiveness of recent or proposed NO_X controls, and determined that these amounts ranged from approximately $200 to $2,800. In addition, in the NPR, EPA developed a reference list for marginal annual cost effectiveness for NO_X controls, and determined that these amounts ranged from approximately $1,400 to $3,000 (69 FR 4614—4615).

In the NPR, EPA proposed a two-phased annual NO_X control program, with a final phase in 2015 and a first phase in 2010. The regionwide emissions reduction requirements that EPA proposed—and the budget levels that would apply if all States chose to implement the reductions from EGUs—were based on using a combination of recent historical heat input and NO_X emissions rates for fossil fuel-fired EGUs. For historical heat input, EPA proposed determining the highest heat input from units affected by the Acid Rain Program for each affected State for the years 1999–2002. The EPA then summed this heat input for all of the States affected for annual NO_X reductions. For 2015, EPA calculated a proposed regionwide annual NO_X budget by multiplying this heat input by an emission rate of 0.125 lb/mmBtu, and for 2010 by multiplying by 0.15 lb/mmBtu.

In developing the CAIR NPR, when EPA considered the appropriate amount of annual SO_2 emissions reductions, EPA relied on the existing title IV annual SO_2 cap as a starting point. However, in considering the appropriate amount of NO_X reductions, the situation is different because title IV does not cap NO_X emissions. Therefore, EPA and the States have focused on emissions caps based on a combination of heat input and NO_X emission rates. Emission rates similar to the rates used to develop the CAIR NPR have been considered in the past. For example, the CAPI 1996 study, noted above, contemplated NO_X caps based on an emission rate of 0.15 lb/mmBtu (and other options based on NO_X rates of 0.20 lb/mmBtu and 0.25 lb/mmBtu). The NO_X SIP Call is based on an emission rate of 0.15 lb/mmBtu.

The methodology described in the NPR is best understood as the means for developing the target 2015 annual NO_X control level (or emissions budget) for further evaluation through IPM. The EPA developed this level mindful of its experience to date with the NO_X SIP Call and the earlier work EPA has performed on multi-pollutant power plant reduction programs. The EPA also considered available technical information on pollution controls, costs to industry and the general public, ambient air improvement, and consistency with the emerging $PM_{2.5}$ implementation program, in developing its target control level.

Recent advances in combustion control technology for NO_X reductions, as well as widespread use of selective catalytic reduction (SCR) on U.S. coal-fired EGU boilers achieving NO_X emission rates of 0.06 lb/mmBtu and below, provide evidence that even lower average NO_X emission rates are more highly cost-effective than rates considered in the past (based on analyzing EGUs), possibly on the order of 0.12 lb/mmBtu or less. The EPA developed the target annual NO_X control level (or emissions budget) with

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the understanding that the evaluation of that level might indicate that average emission rates on the order of 0.12 lb/mmBtu or less might be highly cost effective for the final (2015) control phase, and an interim level resulting in an average emission rate of less than 0.15 lb/mmBtu might be feasible for the first phase.

The EPA did evaluate the target annual NO_X control levels (or emissions budgets) using the IPM. The EPA confirmed that the 2015 level is highly cost effective. The Agency also evaluated the cost effectiveness of the proposed 2010 cap to assure that the interim phase reductions would also be highly cost effective. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with generating capacity greater than 25 MW.

The proposed cap for the first phase was developed taking into consideration how much pollution control for NO_X and SO_2 could be installed without running into a shortage of skilled labor, in particular boilermakers (EPA's assumptions regarding boilermaker labor are described in section IV.C.2 of this preamble). The Agency focused on providing substantial reductions of both SO_2 and NO_X emissions at the outset of the proposed program, leading to significant retrofits of Flue Gas Desulfurization units (FGD) for SO_2 control and SCR for NO_X control.

In the NPR, EPA explained that using the highest Acid Rain Program heat input for each State to develop a regionwide heat input amount, rather than the average Acid Rain Program heat input, provided a cushion that represented a reasonable adjustment to reflect that there are some non-Acid Rain units that operate in these States that will be subject to the proposed CAIR emission reduction levels. The EPA explained that it did not use heat input data from non-Acid Rain units in the proposal because it did not have all the necessary data available at the time the NPR was developed.[61] Using the highest of recent years' Acid Rain Program heat input provided an approximation of the regionwide heat input, although it did not include heat input from non-Acid Rain sources. Multiplying the approximate recent heat input by 0.125 lb/mmBtu to develop a proposed regionwide annual 2015 NO_X cap could reasonably be expected to yield an average effective NO_X emission rate (considering all EGUs potentially affected by CAIR for annual reductions, not only the Acid Rain units, and considering growth in heat input) somewhat less than 0.125 lb/mmBtu. Likewise, multiplying the approximate recent heat input by 0.15 lb/mmBtu to develop a regionwide annual 2010 NO_X cap could reasonably be expected to yield an average effective NO_X emission rate for all CAIR units of about 0.15 lb/mmBtu or less.

Although EPA calculated—in essence, as a target level for further evaluation—the proposed regionwide annual NO_X control levels (or emissions budgets) based on heat input from only Acid Rain Program units, the Agency evaluated the cost effectiveness of the control levels using heat input from all EGUs that potentially would be affected by the proposed CAIR. The EPA evaluated cost effectiveness using the IPM, which includes both Acid Rain units and non-Acid Rain units. Further, the IPM incorporates assumptions for electricity demand growth, and thus heat input growth.

Specifically, EPA evaluated these target annual NO_X caps on EGUs for 2010 and 2015—and therefore the associated regionwide emissions reductions—using the IPM, which, in effect, demonstrated that these proposed NO_X emissions cap levels can be met using highly cost-effective controls with the expected levels of electricity demand in 2010 and 2015, respectively. Those expected levels of electricity demand are higher than the electricity demand during the 1999 to 2002 years upon which EPA based heat input; and as a result, the amount of heat input necessary to meet the projected electricity demand is expected to be higher than the amount that EPA developed for evaluation purposes through the method described above. The projected average future emissions rates that would be associated with the 2010 and 2015 heat input levels needed to meet electricity demand (coupled with the NO_X emissions budgets developed through the methodology described above) would be about 0.14 lb/mmBtu and 0.11 lb/mmBtu in 2010 and 2015, respectively.[62] These average rates would be for all units affected by annual NO_X controls under CAIR, including non-Acid Rain units. Thus, the heat input is projected to be higher in 2010 and 2015 than the recent historic heat input used to develop the target emissions budgets, and the projected NO_X emission rates in 2010 and 2015 are lower than the 0.15 lb/mmBtu and 0.125 lb/mmBtu rates that were used to develop the budgets. IPM determined the costs of meeting these average future NO_X emission rates of 0.14 lb/mmBtu and 0.11 lb/mmBtu. The EPA considers these emission rates to be highly cost-effective and feasible.

In the NPR, EPA proposed an interim (Phase I) annual NO_X phase in 2010 and a final (Phase II) annual NO_X phase in 2015. However, in today's final rule, EPA is promulgating a Phase I for NO_X in 2009 (with the Phase II for NO_X in 2015, as proposed). The EPA determined the regionwide NO_X control levels for 2009 and 2015 for today's final action using the same methodology as we used to determine proposed levels. The Agency evaluated the cost effectiveness of the final reduction requirements (and average NO_X emission rates) using IPM and determined them to be highly cost-effective, assuming controls on EGUs. The EPA's evaluation of the cost effectiveness of the emission reduction strategy we assumed in establishing the final CAIR control levels is discussed further below.

The average NO_X emission rates in the first and second phases of CAIR will be lower than the nominal emission rate on which the NO_X SIP Call was based, which was 0.15 lb/mmBtu. In the NO_X SIP Call, EPA also considered a control level based on a lower nominal emission rate, 0.12 lb/mmBtu. However, at that time the use of SCR was not sufficiently widespread to allow EPA to conclude that the controls necessary to meet a tighter cap could be installed in the required timeframe, without causing reliability problems for the electric power sector. Now, through the experience gained from the NO_X SIP Call, EPA has confidence that with SCR technology average emissions rates lower than the NO_X SIP Call nominal emission rate can be achieved on a regionwide basis.

In the CAIR NPR, after determining the regionwide control level and evaluating it to assure that it is highly cost-effective, the Agency then apportioned the regionwide budgets to the affected States. The EPA proposed to apportion regionwide NO_X budgets to individual States on the basis of each State's share of recent average heat input. In the NPR, EPA used the average share of Acid Rain Program heat input. However, as discussed in the SNPR and the NODA, in order to distribute more equitably to States their share of the regionwide NO_X budgets, EPA then

[61] The EPA does not collect annual heat input data from these non-Acid Rain units. EIAdoes collect heat input from such units, however there are some limitations to the data. First, there are no requirements specifying how the data should be collected or quality assured. Second, the data is collected on a plant-wide basis rather than on a unit-by-unit basis.

[62] These projected average NO_X emissions rates are from updated IPM modeling done in 2004. The IPM modeling done prior to the NPR also projected similar average emission rates, about 0.15 lb/mmBtu and 0.11 lb/mmBtu in 2010 and 2015, respectively.

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considered each State's proportional share of recent average heat input using data from non-Acid Rain Program sources as well as Acid Rain Program sources. The EPA obtained EIA heat input data reported for non-Acid Rain sources and combined the EIA heat inputs with Acid Rain heat inputs to determine each State's share of combined average recent heat input.

The fact that EPA distributed the regionwide budget to individual States based on their proportional share of heat input from Acid Rain and non-Acid Rain units combined does not affect the determination of the regionwide budgets themselves. The regionwide budgets were determined to be highly cost-effective when tested for all units—both non-Acid Rain units as well as Acid Rain units—that would be affected by CAIR. (The EPA's method for apportioning regionwide NO_X budgets to States is discussed in more detail elsewhere in today's preamble. That discussion includes an explanation of the differences between the State budgets that were presented in the NPR, the SNPR, and the NODA. In addition, see the TSD entitled ''Regional and State SO_2 and NO_X Emissions Budgets.'')

In the NPR, EPA proposed that Connecticut contributed significantly to downwind ozone nonattainment, but not to $PM_{2.5}$ nonattainment. Thus, the Agency proposed that Connecticut would not be subject to an annual NO_X control requirement and was not included in the region proposed for annual controls. We proposed that Connecticut would be affected by an ozone season-only NO_X control level, and proposed to calculate Connecticut's ozone season control level in a parallel way to how the regionwide annual NO_X control levels were calculated. That is, EPA selected the highest of the same 4 years of (ozone season-only) heat input used for the regionwide budget calculation, and multiplied that heat input by the same NO_X emission rates used to calculate the regionwide control levels. Connecticut is the only State for which an ozone season budget was proposed.

The EPA used the same methodology for developing regionwide budgets for today's final rule as was proposed in the NPR. For the final CAIR, EPA found that 23 States and the District of Columbia contribute significantly to downwind $PM_{2.5}$ nonattainment and found that 25 States and the District of Columbia contribute significantly to downwind ozone nonattainment (section III in today's preamble describes the significance determinations). CAIR requires annual NO_X reductions in all States determined to contribute significantly to downwind $PM_{2.5}$ nonattainment, and requires ozone season NO_X reductions in all States determined to contribute significantly to downwind ozone nonattainment (many of the CAIR States are affected by both annual and ozone season NO_X reduction requirements). The final CAIR ozone season NO_X reductions are required in two phases, with Phase I commencing in 2009 and Phase II in 2015, the same years as the annual NO_X reduction requirements.

As described above, the Agency proposed ozone season NO_X reduction requirements for Connecticut, and did not propose separate ozone season reduction requirements in any other State. For today's final rule, EPA requires ozone season reductions in all States contributing significantly to downwind ozone nonattainment. The EPA determined regionwide ozone season NO_X control levels for the final CAIR using the same methodology as was used for the annual NO_X reduction requirements (which is the same method that was proposed for Connecticut's ozone season budget). That is, EPA determined the highest (ozone season) heat input from Acid Rain Program units for the years 1999–2002 for each State, then summed this heat input for all of the States affected for ozone season NO_X reductions. For the final 2015 control level, EPA calculated a regionwide ozone season NO_X budget by multiplying this heat input by an emission rate of 0.125 lb/mmBtu, and for 2009 by multiplying by 0.15 lb/mmBtu. The Agency evaluated the cost effectiveness of these ozone season NO_X control levels (and average NO_X emission rates) using IPM and determined them to be highly cost-effective, assuming controls on EGUs. The EPA's evaluation of the cost effectiveness of the final CAIR control requirements is discussed further below.

Based on EPA's analysis of proposed annual NO_X control levels, in the NPR the Agency presented average costs for annual NO_X control of $800 per ton and $700 per ton for 2010 and 2015, and marginal costs of $1,300 per ton and $1,500 per ton for 2010 and 2015. In the NPR, EPA also presented marginal costs of annual NO_X control from sensitivity analyses that used EIA assumptions for electricity growth and natural gas prices. Those marginal control costs were $1,300 per ton and $1,600 per ton for 2010 and 2015, respectively. The EPA also presented costs from a sensitivity model run that used EIA assumptions for electricity growth and natural gas price and higher SCR costs. These marginal control costs were $1,700 per ton and $2,200 per ton for 2010 and 2015, respectively.[63]

In the NPR, EPA also presented the average cost effectiveness for ozone season-only NO_X control of $1,000 per ton and $1,500 per ton for 2010 and 2015, respectively, and a marginal cost for ozone season-only control of $2,200 per ton and $2,600 per ton for 2010 and 2015. The EPA also presented average costs for the non-ozone season (remaining seven months of the year) control of $700 per ton and $500 per ton in 2010 and 2015, respectively. (As noted above, the capital costs of installing NO_X control equipment would be largely identical whether the equipment will be operated during the ozone season only or for the entire year. However, the amount of reductions would be less if the control equipment were operated only during the ozone season compared to annual operation.)

The EPA proposed the conclusion that these costs met the criteria for highly cost-effective emissions reductions for NO_X (69 FR 4613–4615).

As with SO_2, EPA also considered the cost effectiveness of alternative stringency levels for this regulatory proposal (examining changes in the marginal cost curve at varying levels of emission reductions).

ii. What Are the Most Significant Comments That EPA Received About Proposed NO_X Emission Reduction Requirements, and What Are EPA's Responses?

Some commenters expressed concern that EPA did not account for growth of heat input in calculating regionwide NO_X emissions budgets, noting that growth was used in the calculation of the regional budget for the NO_X SIP Call. Commenters suggest that, by not taking heat input growth into account, EPA developed regionwide budgets that are unduly stringent.

On the other hand, some commenters noted that they supported EPA's proposal to base regionwide budgets on historical heat input and did not want EPA to use growth projections for calculating regionwide NO_X emissions budgets. Some stated that using actual, historic heat input numbers would be more straightforward than using growth projections, and some pointed to complications with the growth projection methodologies used in the NO_X SIP Call.

The EPA recognizes that it employed a growth factor in the NO_X SIP Call.

[63] The control costs for this model sensitivity that were presented in the NPR were in error (69 FR 4615). The corrected costs from the sensitivity are as shown here.

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There, EPA determined the amount of the regional emissions reductions and budgets by applying a growth factor to a historic heat input baseline. The DC Circuit, after first remanding that growth methodology for a better explanation, upheld it. *West Virginia* v. *EPA,* 362 F.3d 861 (DC Cir., 2004). See 67 FR 21 868 (May 1, 2002).

For CAIR, as described above, EPA developed a target level for the proposed NO_X regionwide cap based on recent historic heat input and assumed emission rates of 0.125 lb/mmBtu and 0.15 lb/mmBtu for 2015 and 2010, respectively. The EPA evaluated these target NO_X emissions levels using IPM, which indicated that those target caps—in conjunction with expected electricity demand for 2015 and 2010—would result from higher heat input levels and lower average emissions rates (about 0.11 lb/mmBtu and 0.14 lb/mmBtu for 2015 and 2010, respectively) than the amounts assumed in developing the target NO_X caps. Most importantly, IPM indicated the cost levels associated with those projected 2015 and 2010 average NO_X emission rates, and EPA has determined that those cost levels are highly cost-effective. For the final rule, EPA revised its analyses to reflect the 2009 initial NO_X control phase, and determined that the final CAIR requirements are highly cost-effective. The EPA's methodology, in which the CAIR emissions reductions are predicted to be cost-effective under conditions of projected electricity growth that, in turn, projects heat input growth, in effect accounts for heat input growth. Moreover, the amount of heat input growth is the amount determined by IPM, a state-of-the-art model of the electricity sector (detailed documentation for IPM is in the docket).

Some commenters suggested that EPA adjust the NO_X regionwide budget amounts to include heat input from non-Acid Rain units. For example, some suggested adding the non-Acid Rain unit heat input amounts that EPA used in apportioning regionwide NO_X budgets to the States, to the total regionwide heat inputs that EPA used to calculate regionwide NO_X budgets.

The regionwide budgets determined in the NPR were target levels developed as a starting point for further evaluation. The regionwide heat input amounts and NO_X emission rates used to develop target budget levels were inherently imprecise. As discussed above, IPM modeling indicates that the projected future heat input amounts (based on electricity growth) are greater than the recent historic regionwide amount used to develop the target budget levels, and the future average emission rates for all units affected by CAIR annual NO_X controls (including non-Acid Rain units) are less than the rates used to develop the target budget levels. IPM indicates that the target regionwide NO_X budget levels (and corresponding future average NO_X emission rates and heat input levels) are highly cost-effective for all CAIR units, including non-Acid Rain units. The EPA does not believe it is necessary to adjust the target regionwide budget levels to include the relatively small additional amount of heat input from non-Acid Rain units. The method the Agency used to develop target levels was not intended to be a precise methodology for determining the NO_X caps; rather, it was a reasonable method for selecting a target level to be evaluated further. Upon evaluation of the target level, EPA determined that it can be achieved using highly cost-effective controls for all affected EGUs, including non-Acid Rain units.

iii. Analysis of NO_X Emission Reduction Requirements for Today's Final Rule

(I) Reference Lists of Cost-Effective Controls

For today's action, EPA updated the reference list of controls included in the NPR of the average and marginal costs per ton of recent NO_X control actions. The EPA systematically developed a list of cost information from recent actions and proposed actions. The Agency sought cost information for actions taken by EPA, and examined the comments submitted after the NPR was published, to identify all available control cost information to provide the updated reference list for today's preamble. The updated reference list includes both average and marginal costs of control to which EPA compares the CAIR control costs, although the Agency has limited information on marginal costs of other programs.

The EPA's updated summary of average costs of annual NO_X controls are shown in Table IV–6. The results of this reexamination show that costs of recent actions are generally very similar to those identified in the NO_X SIP Call. The cost figures are presented in 1999 dollars.[64]

TABLE IV–6.—AVERAGE COSTS PER TON OF ANNUAL NO_X CONTROLS

NO_X control action	Average cost per ton
Marine Compression Ignition Engines	Up to $200 [2]
Off-highway Diesel Engine	$400–$700 [2]
Nonroad Diesel Engines and Fuel	$600 [1]
Marine Spark Ignition Engines	$1,200–$1,800 [2]
Tier 2 Vehicle Gasoline Sulfur	$1,300–$2,300 [2]
Revision of New Source Performance Standards for NO_X Emissions-EGUs	$1,700 [3]
2007 Highway Heavy Duty Diesel Standards	$1,600–$2,100 [2]
National Low Emission Vehicle	$1,900 [2]
Tier 1 Vehicle Standards	$2,100–$2,800 [2]
Revision of New Source Performance Standards for NO_X Emissions-Industrial Units	$2,200 [3]
On-board Diagnostics	$2,300 [2]
Texas NO_X Emission Reduction Grants FY 2002–2003	$300–$12,700 [4]
Best Available Retrofit Technology (BART) for Electric Power Sector	$800 [5]

[1] Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule (69 FR 39131; June 29, 2004). The value in this table represents the long-term cost per ton of emissions reduced from the total fuel and engine program (cost per ton of emissions reduced in the year 2030). This value includes the cost for NO_X plus NMHC reductions. 1999$ per ton.

[2] Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; Final Rule (66 FR 5102; January 18, 2001). The values shown for 2007 Highway HD Diesel Stds are discounted costs. Costs shown in this table include a VOC component. 1999$ per ton.

[64] The updated reference list includes estimated average NO_X control costs under BART. The BART rule has been proposed but not finalized (69 FR 25184; May 5, 2004).

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[3] Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Proposed Revision to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units; Proposed Rule (62 FR 36953; July 9, 1997), Table 4 (the Agency's estimate of average control costs was unchanged for the NSPS revisions final rule, published September 5, 1998). In the CAIR NPR, we included a value from the range of NO_X controls for coal-fired EGUs from Table 2 in the proposed NSPS proposed rule (62 FR 36951). 1999$ per ton.

[4] Costs shown in this table are the range of project costs reported for projects that were FY 2002–2003 recipients of the TERP Emission Reductions Incentive Grants Program. These costs may not be in 1999 dollars. *(www.tnrcc.state.tx.us/oprd/sips/grants.html)*

[5] The EPA IPM modeling 2004 of the proposed BART for the electric power sector (69 FR 25184, May 5, 2004), available in the docket. The EPA modeled the Regional Haze Requirements as a source specific 0.2 lb/mmBtu NO_X emission rate limit. Estimated average costs based on this modeling are $800 per ton in 2015 and 2020. 1999$ per ton.

Table IV–7 presents modeled marginal costs for recent State annual NO_X rules.

TABLE IV–7.—MARGINAL COSTS PER TON OF REDUCTION, RECENT ANNUAL NO_X RULES

NOX control action	Marginal cost per ton
Texas Rules	$2,000–$19,600 [1]

[1] The EPA IPM base case modeling August 2004, available in the docket. 1999$ per ton. We modeled Senate Bill 7 and Ch. 117, which impose varying NO_X control requirements in different areas of the State; the range of marginal costs shown here reflects the range of requirements.

The EPA does not believe that it has sufficient information, for today's rulemaking, to treat controls on source categories other than certain EGUs as providing highly cost-effective emissions reductions. The CAA Section 110 permits States to choose the sources and source categories that will be controlled in order to meet applicable emission and air quality requirements. This means that some States may choose to meet their CAIR obligations by imposing control requirements on sources other than EGUs.

As examples of cost-effective actions that States can take in efforts to provide for attainment with the air quality standards, Table IV–8 presents estimated average costs for potential local mobile source NO_X control actions. The EPA received these cost data during the public comments on the NPR.

TABLE IV–8.—AVERAGE COSTS OF POTENTIAL LOCAL MOBILE SOURCE CONTROL ACTIONS TO REDUCE NO_X EMISSIONS

[$ per Ton] [1]

Source category	Average cost per ton
MWCOG Analysis: Mobile Source, Bicycle racks in DC	$9,000
MWCOG Analysis: Mobile Source, Telecommuting Centers	7,300
MWCOG Analysis: Mobile Source, Government Action Days (ozone action days)	5,000
MWCOG Analysis: Mobile Source, Permit Right Turn on Red	1,200
MWCOG Analysis: Mobile Source, Employer Outreach	3,500
MWCOG Analysis: Mobile Source, Mass Marketing Campaign	2,900
MWCOG Analysis: Mobile Source, Transit Prioritization	8,500

[1] Washington DC Metro Area MWCOG Analysis of Potential Reasonably Available Control Measures (RACM). Projects determined to be "Possible" by MWCOG but not RACM because benefits from the possible control measures do not meet the 8.8 tpd NO_X or 34.0 tpd VOC threshold necessary for RACM. These costs may not be in 1999 dollars. (www.mwcog.org/uploads/committee-documents/z1ZZXg20040217144350.pdf) Comments submitted to the EPA CAIR docket from the Clean Air Task Force *et al.*, dated March 30, 2004, included costs from the MWCOG analysis.

(II) Cost Effectiveness of CAIR Annual NO_X Reductions

Table IV–9 provides the average and marginal costs of annual NO_X reductions under CAIR for 2009 and 2015. These costs are updated from the NPR figures—the EPA analyzed the costs of the CAIR using an updated version of IPM (documentation for the IPM update is in the docket). Further, EPA modified the modeling to match the final CAIR strategy (see section IV.A.1 for a description of EPA's CAIR IPM modeling).

CAIR provides for a Compliance Supplement Pool (CSP) of NO_X allowances that can be used for compliance with the annual NO_X reduction requirements. The CSP is discussed in detail later in this preamble. The EPA used IPM to model marginal costs of CAIR with the CSP. The magnitude of the NO_X CSP is relatively small compared to the annual NO_X budget,[65] thus the CSP does not significantly impact the marginal costs (see Table IV–9).

[65] The CSP consists of 200,000 tons, which is apportioned to each of the 23 States and the District of Columbia that are required by CAIR to make annual NO_X reductions, as well as the 2 States (Delaware and New Jersey) for which EPA is proposing to require annual NO_X reductions.

As with SO_2 marginal costs, EPA considered the sensitivity of the NO_X marginal cost results to assumptions of higher electric growth and future natural gas prices than the Agency used in the base case, as shown in Table IV–9.

TABLE IV–9.—ESTIMATED COSTS PER TON OF ANNUAL NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost—Main Case	$500	$700
Marginal Cost—Main Case	1,300	1,600

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TABLE IV–9.—ESTIMATED COSTS PER TON OF ANNUAL NO_X CONTROLLED UNDER CAIR [1]—Continued

Type of cost effectiveness	2009	2015
Marginal Cost—With Compliance Supplement Pool (CSP)	1,300	1,600
Sensitivity Analysis: Marginal Cost Using Alternate Electricity Growth and Natural Gas Price Assumptions	1,400	1,700

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

These estimated NO_X control costs under CAIR reflect annual EGU NO_X caps of 1.5 million tons in 2009 and 1.3 million tons in 2015 within the CAIR annual NO_X control region (the 23 States and DC that must make annual reductions). In both the main IPM modeling case and the modeling case that includes the CSP, projected annual NO_X emissions in the CAIR region will be about 1.5 million tons in 2009 and 1.3 million tons in 2015. The projected emissions are very similar in both modeling cases because the CSP is relatively small compared to the annual NO_X budget.

Average costs shown for 2015 are based on the amount of reductions that would achieve the total difference in projected emissions between the base case conditions and CAIR in the year 2015. These costs are not based on the increment in reductions between 2009 and 2015. (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided later in today's preamble.)

Most of the States subject to today's $PM_{2.5}$ control requirements have been subject to the NO_X SIP Call requirements. Some sources in these States have installed SCRs, and run them during the ozone season. These sources might comply with the $PM_{2.5}$ annual NO_X requirements by, at least in part, running the SCR controls for the remaining months of the year. Under these circumstances, the compliance costs for the $PM_{2.5}$ SIP requirements are lower.

Table IV–10 provides estimated costs per ton of NO_X for non-ozone season reductions under CAIR. These figures are updated from the NPR calculations—the EPA analyzed the costs of the CAIR using an updated version of IPM (documentation for the IPM update is in the docket) and modeled controls on a region that more closely matches the region affected by CAIR.

TABLE IV–10.—PREDICTED COSTS PER TON OF NON-OZONE SEASON NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost	$500	$500

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

The estimated non-ozone season NO_X costs, like the annual NO_X costs, are on the low end of the cost effectiveness range described in Table IV–6. The EPA considers the 2015 and also the 2009 costs to represent highly cost-effective controls.

Environmental Defense reached similar conclusions regarding the cost effectiveness of non-ozone season NO_X reductions, as described in their report ''A Plan for All Seasons: Costs and Benefits of Year-Round NO_X Reductions in Eastern States (2002).'' As stated in that report, ''[As Figure 4 shows,] extending NO_X reductions throughout the year results in dramatic decreases in the per-ton costs of NO_X emission reductions for the 19 NO_X SIP Call States. This is because the bulk of the cost for reducing NO_X emissions from power plants lies in the capital investment in the control equipment. Once the primary investment has been made, it costs relatively little to continue running the control equipment beyond the summer months required by EPA's NO_X SIP Call.'' Environmental Defense based these conclusions on analysis conducted by Resources for the Future (RFF). In an RFF paper, ''Cost-Effective Reduction of NO_X Emissions from Electricity Generation (July 2001),'' RFF draws similar conclusions.

(III) NO_X Cost Comparison for CAIR Requirements

The EPA believes that selecting as highly cost-effective amounts at the lower end of these average and marginal cost ranges is appropriate for reasons explained above in this section of the preamble.

As discussed above, although in the NO_X SIP Call the cost level selected was not at the low end of the reference range of costs, if the NO_X SIP Call costs were for annual rather than seasonal controls they would have been lower relative to the other control costs on the reference list which were mostly for annual programs.

For annual NO_X, the range of average cost effectiveness extends broadly, from under $200 to thousands of dollars (Table IV–6). The 2015 estimated average costs for CAIR annual NO_X control of $700 are consistent with the lower end of this range.

Less information is available for the marginal costs of controls than for average costs. Looking at the available marginal costs (Table IV–7), the 2015 CAIR marginal costs for annual NO_X controls are at the lower end of the range. The EPA also evaluated the cost effectiveness of the 2009 cap, and concluded that the 2009 requirements are highly cost-effective.

(IV) Cost Effectiveness: Marginal Cost Curves for Annual NO_X Control

As with SO_2 controls, EPA also considered the cost effectiveness of alternative stringency levels for NO_X control for today's action by examining changes in the marginal cost curve at varying levels of emissions reductions. Figure IV–3 shows that the ''knee'' in the 2010 marginal cost effectiveness curve for EGUs—the point where the cost of controlling a ton of NO_X begins to increase at a noticeably higher rate—appears to occur at over $1,700 per ton of NO_X. Although EPA conducted this marginal cost curve analysis based on an initial NO_X control phase in 2010, the results would be very similar for 2009, which is the initial NO_X phase in the final CAIR. Figure IV–4 shows that the ''knee'' in the 2015 marginal cost effectiveness curve for EGUs appears to occur at over $1,700 per ton of NO_X. (The EPA based these marginal NO_X cost effectiveness curves on the electricity growth and natural gas price assumptions in the main CAIR IPM modeling run. Marginal cost effectiveness curves based on other electric growth and natural gas price assumptions would look different, therefore it would not be appropriate to compare the curves here to the marginal costs based on the IPM modeling sensitivity run that used EIA assumptions.) The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on IPM, for this analysis. These results make clear that this rule is very cost-effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[66]

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Figure IV-3

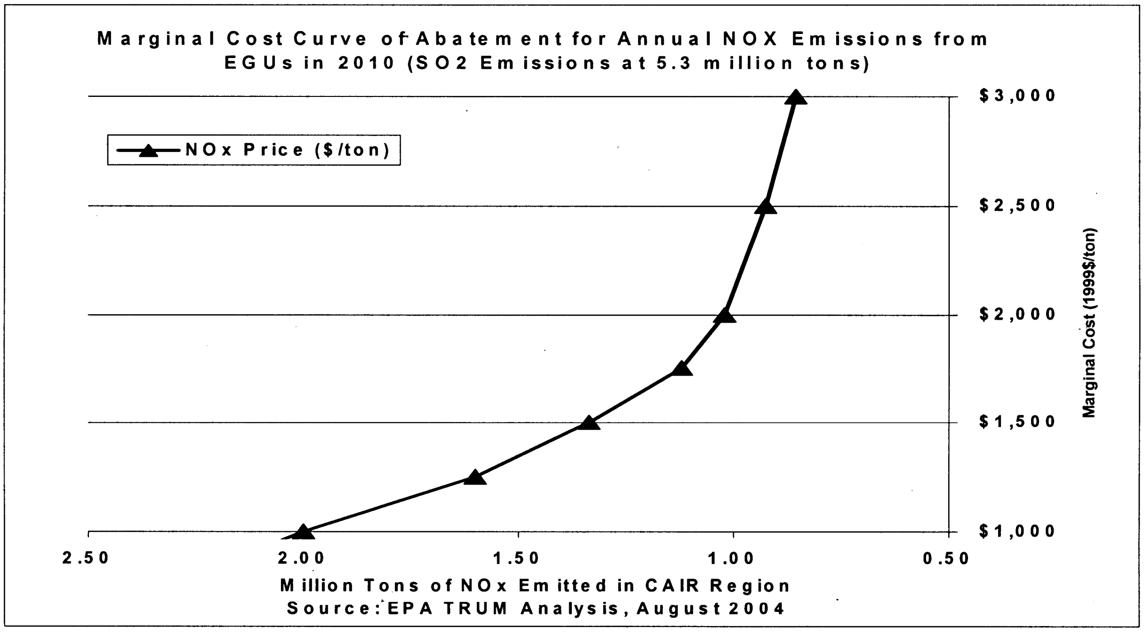
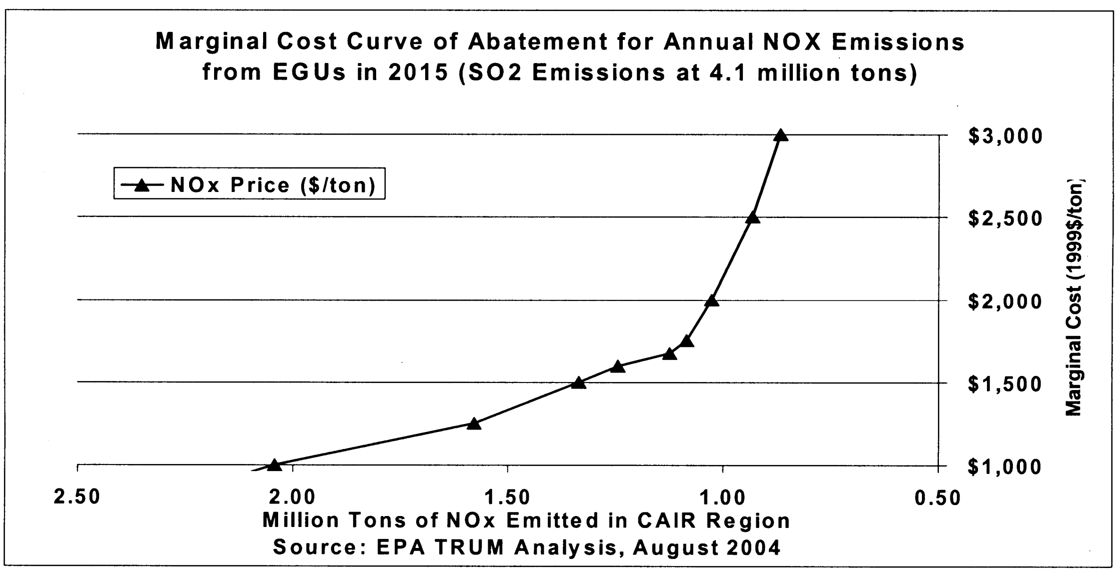


Figure IV-4



[66] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. As in the case of SO_2 controls, described above, it should be noted that similar analysis for other source categories may yield different curves.

(V) Cost Effectiveness of Ozone Season NO_X Reductions

The CAIR requires ozone season NO_X emissions reduction for all States determined to contribute significantly to ozone nonattainment downwind (25 States and the District of Columbia). The EPA used IPM to model average and marginal costs of the ozone season reductions assuming EGU controls. In this modeling case, EPA modeled an ozone season NO_X cap for the region affected by CAIR for downwind ozone nonattainment, but did not include the CAIR annual SO_2 or NO_X caps. Based on that modeling, Table IV–11 provides estimated average and marginal costs of regionwide ozone season NO_X reductions for 2009 and 2015. Table IV–11 shows the estimated cost effectiveness of today's ozone season NO_X control requirements for 8-hour transport SIPs.

TABLE IV–11.—ESTIMATED COSTS PER TON OF OZONE SEASON NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost	$900	$1,800
Marginal Cost	2,400	3,000

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

These estimated NO_X control costs are based on ozone season EGU NO_X caps of 0.6 million tons in 2009 and 0.5 million tons in 2015 within the CAIR ozone season NO_X control region. Average costs shown for 2015 are based on the amount of reductions that would achieve the total difference in projected emissions between the base case conditions and CAIR in the year 2015. These costs are not based on the increment in reductions between 2009 and 2015. (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided later in today's preamble.)

The EPA believes that selecting as highly cost-effective amounts at the lower end of the average and marginal cost ranges is appropriate for reasons explained above in section IV in this preamble.

In the NO_X SIP Call, EPA identified average costs of $2,500 (1999$) (or $2,000 (1990$)) as highly cost-effective.[67] The estimated average costs of regionwide ozone season NO_X control under CAIR are $1,800 per ton in 2015 and $900 per ton in 2009. Thus, with respect to average costs the controls for the final phase (2015) cap, which are below the $2,500 identified in the NO_X SIP Call, are also highly cost-effective, as are those for the 2009 cap. In addition, the estimated average costs of CAIR ozone season NO_X control are at the lower end of the reference range of average annual NO_X control costs (the reference list of average annual NO_X control costs is presented above).

Similarly, the estimated marginal costs [68] of ozone season CAIR NO_X controls are within EPA's reference range of marginal costs, at the lower end of the range (the reference list of marginal annual NO_X control costs is presented above). We note that the marginal costs in the reference range are for annual NO_X reductions, and would likely be higher for ozone season only programs. Considering both average and marginal costs, the CAIR ozone season control level is highly cost-effective.

For purposes of estimating costs of ozone season control under CAIR, EPA set up this modeling case with CAIR ozone season NO_X requirements but without the annual NO_X requirements. The Agency believes that the cost of the ozone season CAIR requirements will actually be lower than the costs presented here because interactions will occur between the CAIR annual and ozone season NO_X control requirements.[69] In addition, for States in both programs, the same controls achieving annual reductions for PM purposes will achieve ozone season reductions for ozone purposes; this is not reflected in our cost-per-ton estimates.

As with SO_2 controls, and annual NO_X controls, EPA also considered the cost effectiveness of alternative stringency levels for CAIR NO_X reductions for ozone purposes by examining changes in the marginal cost curve at varying levels of emissions reductions. Figure IV–5 shows that the ''knee'' in the 2010 marginal cost effectiveness curve for ozone season NO_X reductions from EGUs—the point where the cost of controlling an ozone season ton of NO_X begins to increase at a noticeably higher rate—appears to occur somewhere between $3,000 and $4,000 per ton of NO_X. Although EPA conducted this marginal cost curve analysis based on an initial NO_X control phase in 2010 the results would be very similar for 2009, which is the initial NO_X phase in the final CAIR. Figure IV–6 shows that the ''knee'' in the 2015 marginal cost effectiveness curve for ozone season NO_X reductions from EGUs appears to occur somewhere between $3,000 and $4,000 per ton of NO_X. The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on the IPM, for this analysis. These results make clear that CAIR NO_X reductions for ozone purposes are very cost-effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[70]

[67] For both the NO_X SIP Call and CAIR, the NO_X control costs on the reference lists are generally for annual reductions. The EPA compared the costs of ozone season reductions under the NO_X SIP Call, as well as ozone season CAIR NO_X reductions, to the annual reduction programs on the reference lists.

[68] In the NO_X SIP Call EPA used average, not marginal, costs to evaluate cost effectiveness. For the reasons discussed above we are evaluating both average and marginal costs for CAIR.

[69] Estimated costs for regionwide CAIR NO_X controls during the ozone season are higher than the average and marginal costs for CAIR annual NO_X controls. This is because, as noted above, the capital costs of installing NO_X control equipment would be largely identical whether the SCR will be operated during the ozone season only or for the entire year. However, the amount of reductions would be less if the control equipment were operated only during the ozone season compared to annual operation.

[70] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. As in the case of SO_2 controls, described above, it should be noted that similar analysis for other source categories may yield different curves.

Figure IV-5

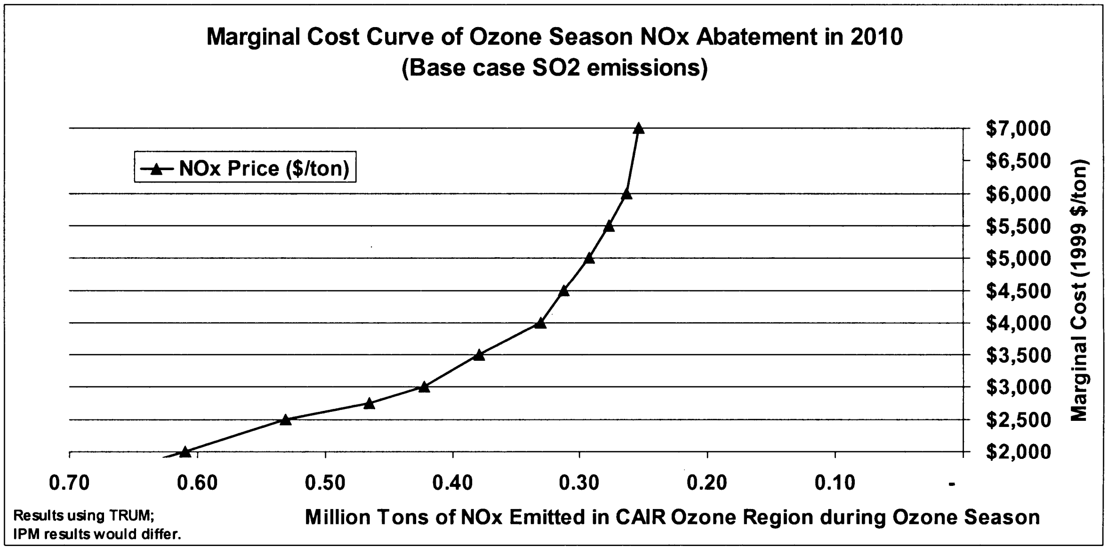
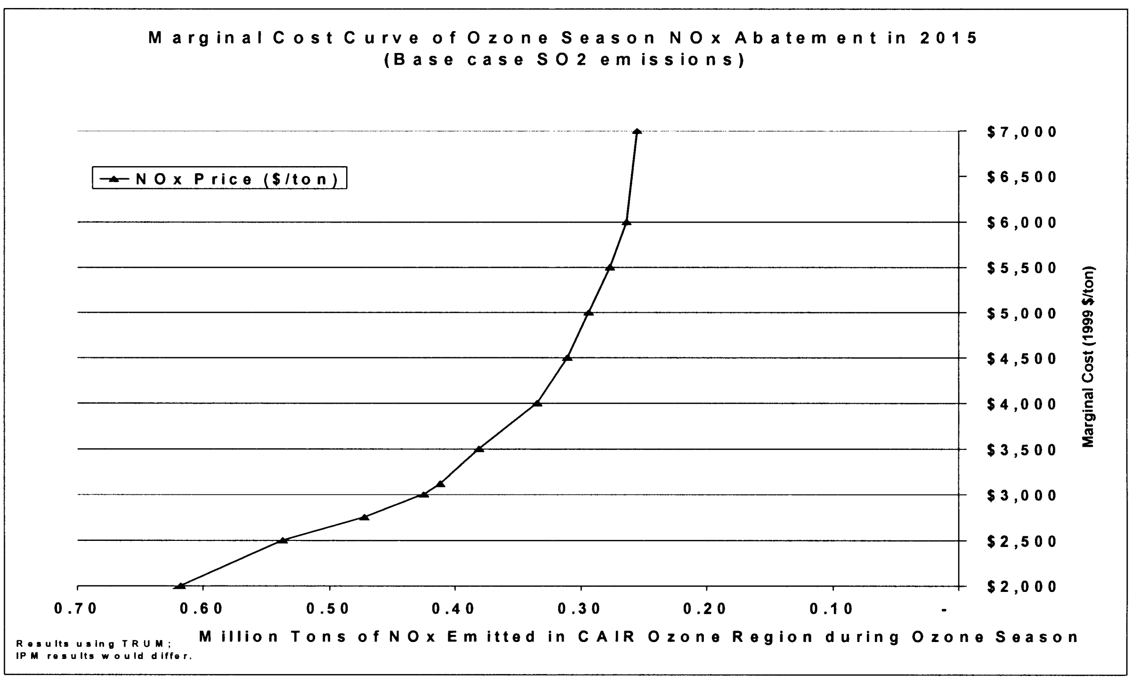


Figure IV-6



B. What Other Sources Did EPA Consider When Determining Emission Reduction Requirements?

1. Potential Sources of Highly Cost-Effective Emissions Reductions

In today's rulemaking, EPA determines the amount of regionwide emissions reductions required by determining the amount of emissions reductions that could be achieved through the application of highly cost-effective controls on certain EGUs. The EPA has reviewed other source categories, but concludes that for purposes of today's rulemaking, there is insufficient information to conclude that highly cost-effective controls are available for other source categories.

a. Mobile and Area Sources

In the NPR (69 FR 4610), EPA explained that "it did not identify highly cost-effective controls on mobile or area sources." No comments were received suggesting that mobile or area sources should be controlled. Therefore, in developing emission reduction requirements, EPA is not assuming any emissions reductions from mobile or area sources.

b. Non-EGU Boilers and Turbines

The largest single category of stationary source non-EGUs are large non-EGU boilers and turbines. This

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source category emits both SO_2 and NO_X. In the CAIR NPR, EPA proposed not to include any potential SO_2 or NO_X emissions reductions from non-EGU boilers and turbines as constituting ''highly cost-effective'' reductions and thus to be taken into account in establishing emissions requirements because EPA believed it had insufficient information on their control costs, particularly costs associated with the integration of NO_X and SO_2 controls. In addition, based on information EPA does have, projected base case (without the CAIR) emissions of SO_2 and NO_X from these sources are significantly lower than projected EGU emissions. The EPA projects that in 2010 under base case conditions, EGUs would contribute 70 percent of SO_2 in the CAIR region compared to 15 percent from non-EGU boilers and turbines in the CAIR region. The Agency also predicts that in 2010 under the base case, EGUs would contribute 25 percent of NO_X emissions in the CAIR region compared to 16 percent from non-EGU boilers and turbines in the CAIR region. Thus, simply on an absolute basis, non-EGU emissions are relatively less significant than emissions from EGUs. The EPA is finalizing its proposed approach to these sources and has not based today's requirements on any presumed availability of highly cost-effective emissions reductions from non-EGU boilers and turbines.

A number of commenters believe EPA should determine that emissions reductions from non-EGUs should be taken into account in establishing emission requirements because, they believe, highly cost-effective controls are available for these sources. These commenters argued that highly cost-effective controls are available for these sources and that EPA should have sufficient emissions and control cost information because the same sources were included in the NO_X SIP Call.

In addition, while it is true that these sources were included in the NO_X SIP Call, EPA only addressed NO_X reductions from these sources. Neither SO_2 reductions nor monitoring of SO_2 emissions is required by the NO_X SIP Call. As a result, for these sources, EPA has less reliable SO_2 emissions data and very little information on the integration of NO_X and SO_2 controls. Although EPA has more information on NO_X emissions from these sources because of the NO_X SIP Call (and other programs in the northeastern U.S.), the geographic coverage of the CAIR includes some States that were not included in the NO_X SIP Call, some of which States contain significant amounts of industry. The EPA has even less emissions data from non-EGUs in these non-SIP call States affected by the CAIR. While EPA has incorporated State-submitted emissions inventory data for 1999 into its analysis for the CAIR, even this data is generally lacking information on fuel, sulfur content, and existing controls. Without this data, it is very difficult to assess the emission reduction opportunities available for non-EGU boilers and turbines. Furthermore, with regards to NO_X, many non-EGU boilers and turbines are making reductions using low NO_X burners (the control technology EPA assumed in making the cost-effectiveness determinations in the NO_X SIP Call). Since these controls are operated year-round, annual emissions reductions are already being obtained from many of these units. Additional reductions would likely be less cost effective.

Another commenter stated that non-EGU ''major sources'' are subject to the requirements of title V of the CAA and, therefore, EPA should have adequate emissions data provided as part of the sources' permitting obligations. However, title V simply requires that a source's permit include the substantive requirements (such as emission monitoring requirements) imposed by other sections of the CAA and does not itself impose any substantive requirements. Thus, the mere fact that a source is a major source required to have a title V permit does not mean that the source is monitoring and submitting emissions, fuel, and control device data. Many such sources do not, in fact, provide such data.

One commenter submitted cost information for FGD technology applications on industrial boilers. However, the information submitted by the commenter was based on the use of a limited number of technologies and for a limited number of boiler sizes. The EPA does not believe that the limited information demonstrates that SO_2 emissions from these sources could be controlled in a highly cost-effective manner across the entire sector in question, or to what level the emissions could be controlled.

Some commenters recommended including non-EGU boilers and turbines because in the future, after reductions from EGUs are made, the relative contribution of non-EGU boilers and turbines to the total NO_X and SO_2 emissions will increase. The EPA agrees that the relative contribution of non-EGUs to total NO_X and SO_2 emissions will increase in the future if States choose to meet their CAIR emissions reduction obligations solely by way of emission reductions made by EGUs. However, EPA does not believe that this, by itself, provides any basis for determining that in the context of this rule emissions reductions from non-EGUs should be determined to be highly cost-effective. As discussed above, EPA believes it is necessary to have more reliable emissions data and better control cost information for these sources before assuming reductions from them in the CAIR. The EPA is working to improve its inventory of emissions and control cost information for non-EGU boilers and turbines. Specifically, we are assessing the emission inventory submittals for 2002 made by States in response to the relatively new requirements of 40 CFR part 51 (the Consolidated Emission Reporting Rule), and we will work with States whose submissions appear to have gaps in required data. We also note that EPA provides financial and technical support for the efforts of the five Regional Planning Organizations to coordinate among and assist States in improving emission inventories.

Another commenter expressed concern that if the decision whether to control large industrial boilers is left to the States, the result may be inequitable treatment of EGUs on a State-by-State basis, particularly with respect to allowances, and therefore it would make sense to require NO_X and SO_2 reductions from large industrial boilers. Section 110 of the CAA leaves the ultimate choice of what sources to control to the States, and EPA cannot require States to control non-EGUs. Even if EPA had included reductions from non-EGUs in determining the total amount of reductions required under the CAIR, EPA could not have required any State to achieve those reductions through emission limitations on non-EGUs.

The recent economic circumstances faced by the manufacturing sector accentuates EPA's concerns about the lack of reliable emissions data and control information regarding non-EGUs. We note that the U.S. manufacturing sector was adversely affected by the latest business cycle slowdown. As noted in the 2004 Economic Report of the President, the manufacturing sector was hit earlier, longer, and harder than other sectors of the economy. The 2004 Report also points out that, although manufacturing output has dropped much more than the real gross domestic product (GDP) during past business cycles, the latest recovery has been unusual because it has been weaker for the manufacturing sector than the recovery in the real GDP. The disparity across sectors (and even within individual sectors) in the economic condition of firms reinforces

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EPA's concerns about moving forward to consider emission controls on non-EGUs at this time.

As explained elsewhere in this preamble, although the CAIR does not require that States achieve the required emissions reductions by controlling particular source categories, we expect that States will meet their CAIR obligations by requiring emissions reductions from EGUs because such reductions are highly cost effective. We believe the States are in the best position to make decisions regarding any additional control requirements for non-EGU sources. In making such decisions, States may take into consideration all relevant factors and information, such as differences across States in the need for control, differences in relative contribution of various sources, and differences in the operating and economic conditions across sources.

c. Other Non-EGU Stationary Sources

In the NPR and in the technical support document entitled ''Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 Emissions Other Than EGUs (January 2004),'' EPA applied a similar rationale for non-EGU stationary sources other than boilers and turbines. For SO_2, EPA noted that the emissions from such sources were a relatively small part of the emissions inventory, and we also noted the lack of information on costs. For NO_X, we explained that more information was available than for SO_2. This is because the NO_X SIP Call included consideration of emissions control measures for internal combustion (IC) engines and cement kilns, and developed cost estimates for other NO_X-emitting categories such as process heaters and glass manufacturing. However, we believed—as for boilers and turbines, discussed above—that insufficient information on emission control options and costs, was available to apply these measures to the entire geographic area covered by the proposed rule.

No adverse comments were received suggesting inclusion of SO_2 emissions reductions from non-EGU stationary sources other than boilers and turbines. Accordingly, EPA has determined not to consider SO_2 reductions from these other non-EGU stationary sources.

Several commenters suggested that EPA should have been able to consider NO_X emissions reductions from non-EGU categories other than boilers and turbines, such as internal combustion (IC) engines and refinery fluid catalytic cracking units. These commenters believed such reductions were demonstrated to be cost effective, and questioned EPA's assertion that insufficient information is available. Finally, some commenters believe EPA should have, at a minimum, required that controls for NO_X SIP Call sources—including large IC engines and cement kilns—should be extended from the ozone season to the entire year.

We believe it likely that inclusion in today's requirements of reductions from any highly cost-effective controls—if available—for these categories would have very small effects. First, most of the States included in the CAIR rule were also included in the NO_X SIP Call, so that many of the emissions reductions that would be available from these sources have already occurred due to implementation of the NO_X SIP Call. Second, in the States included in the CAIR rule, but which were not covered by the NO_X SIP Call, only a small portion of NO_X emissions come from cement kilns and IC engines compared to EGUs. Moreover, in some parts of this geographic area, in particular for Texas, many sources in these source categories are already regulated under ozone nonattainment plans (including SIPs for the Texas cities of Houston, Galveston, and Dallas).

Regarding the commenters' recommendation that extending NO_X SIP Call control requirements to a year-round basis for large IC engines and cement kilns should be considered to be highly cost effective, EPA believes that few emissions reductions would be achieved from doing so. The types of controls that were applied in the NO_X SIP Call States, while required to be in place only during the ozone season, will, as a practical matter, be applied on a year-round basis, whether or not so required by today's rule. Most, if not all, of the NO_X SIP Call States have developed regulations to control NO_X emissions from IC engines and cement kilns during the ozone season. The control of choice to meet these reductions from large lean burn IC engines is low emission combustion (LEC), which for retrofit applications is a substantial equipment modification of the engine's combustion system. The engine will operate with LEC year round because this modification is a permanent change to the engine. Most, if not all, new large lean-burn IC engines have LEC. In addition, year-round emissions controls are already required for rich-burn engines greater than 500 hp which will likely install nonselective catalyst reduction to comply with the recently adopted hazardous air pollutant standards (see final rule for reciprocating IC engines, 69 FR 33474, June 15, 2004). For cement kilns, the controls of choice are low NO_X burners and mid-kiln firing. Low NO_X burners (LNB) are a permanent part of the kiln, so that the kiln will operate year-round with LNB. Mid-kiln firing is a kiln modification for which a solid and slow burning fuel (typically tires) is injected in the mid-kiln area. Due to tipping fees and fuel credits, mid-kiln firing results in an operating cost savings. After this system is installed, year-round operation is expected.

C. Schedule for Implementing SO_2 and NO_X Emissions Reduction Requirements for $PM_{2.5}$ and Ozone

1. Overview

In the NPR, EPA proposed a two-phased schedule for implementing the CAIR annual emission reduction requirements: implementation of the first phase would be required by January 1, 2010 (covering 2010–2014), and that for the second phase by January 1, 2015 (covering after 2014). The EPA based its proposal on its analysis of engineering, financial, and other factors that affect the timing for installing the emission controls that would be most cost-effective—and are therefore the most likely to be adopted—for States to meet the CAIR requirements. Those air pollution controls are primarily retrofitted FGD systems (i.e., scrubbers) for SO_2 and SCR systems for NO_X on coal-fired power plants.

The EPA's projections showed a significant number of affected sources installing these controls. The proposed two-phased schedule allowed the implementation of as much of the controls as feasible by an early date, with a later time for the remaining controls.

The EPA received detailed, technical comments from commenters who argued that the controls could not be implemented until later than proposed, and from other commenters who argued that the controls could be implemented sooner than proposed. The EPA has reviewed the comments and has conducted additional research and analyses to verify availability of adequate industrial resources, including boilermakers, for constructing the emission control retrofits required by CAIR. These analyses are based on conservative assumptions, including those suggested by the commenters, to ensure that the requirements imposed by CAIR do not result in shortages of the required resources that could substantially increase construction costs for pollution controls and reduce the cost effectiveness of this program.

Today, EPA is taking final action to require the annual emissions reductions

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on the same two-phase schedule as proposed. However, the requirements for the first phase include two separate compliance deadlines: Implementation of NO_X reductions are required by January 1, 2009 (covering 2009–2014) and for SO_2 reductions by January 1, 2010 (covering 2010–2014). The compliance deadline requirements for the second phase are the same as proposed. The EPA believes that its action is consistent with the Agency's obligations under the CAA to require emission reductions for obtaining NAAQS to be achieved as soon as practicable. The EPA applied the same criterion in implementing the NO_X SIP Call, which was based on a single-phased schedule.[71]

2. Engineering Factors Affecting Timing for Control Retrofits

a. NPR

In the NPR, EPA identified the availability of boilermakers as an important constraint for the installation of significant amounts of SCR and FGD retrofits. Boilermakers are skilled laborers that perform various specialized construction activities, including welding and rigging, for boilers and high pressure vessels. The air pollution control devices, such as scrubber and SCR vessels, require boilermakers for their construction. Apprentices with no prior work-related experience complete a four-year training program, to become full boilermakers. For apprentices with relevant experience, this training period could be shorter. For example, union members representing the shipbuilding trade could be expedited into the boilermaker division within a year.

The boilermaker constraint was considered more important for the initiation of the first phase of CAIR, since the NO_X SIP Call experience had shown that many sources would be adverse to committing significant funds to install controls until after SIPs were finalized. With the States required to finalize SIPs in 18 months after the signing of the final rule, the sources would have three years in which to complete purchasing, construction, and startup activities associated with these controls, to meet the proposed CAIR deadline.

The EPA's projections showed power plants installing 51.4 gigawatts (GW) of FGD and 28.2 GW of SCR retrofits during the first CAIR phase. These projections include retrofits for CAIR as well as retrofits for base case policies (i.e., retrofits for existing regulatory requirements). We estimated the total boilermaker-years required for installing these controls at 12,700, which was based on the boilermakers being utilized over a period of 18 months during the installation process. Also, based on the projected boilermaker population in the timeframe relevant to the installation of these controls, we estimated that 14,700 boilermaker-years were available over the same 18-month period. The availability of approximately 15 percent more boilermaker-years than required, as shown by these estimates, confirms the adequacy of this critical resource for CAIR and EPA assumed this to be a reasonable contingency factor.

The EPA also determined that installation of the projected amounts of FGD and SCR retrofits could be completed within the three-year period available for CAIR. This determination was based on a previous report prepared by EPA for the proposed Clear Skies Act, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies,'' (docket no. OAR–2003–0053–0106). According to this report, an average of 21 months are required to install SCR on one unit, and 27 months to install a scrubber on one unit. For multiple units within the same plant, installation of controls would normally be staggered to avoid operational disruptions. The EPA projected that the maximum number of multiple-unit controls required for each affected facility could all be installed within three years.The NPR proposal included a second phase, with a compliance deadline of January 1, 2015. The EPA's projections showed power plants installing 19.1 GW of FGD and 31.7 GW of SCR retrofits by 2015, which included retrofits for CAIR as well as retrofits for base case policies (i.e., retrofits for existing regulatory requirements). Availability of boilermaker labor was not an important constraint for this phase.

b. Comments

The EPA received several comments relating to the requirements for the two-phased implementation program, the emission caps and compliance deadline for each phase, and resources required to install necessary controls. The commenters offered opposing viewpoints, which can be broadly categorized as follows.

Several commenters indicated that the compliance deadline of 2010 for the first phase was not attainable and argued that EPA should either extend the deadline, or set higher emission caps for this phase. The commenters raised the following specific points in support of their concerns:

- The time allowed for completing various activities from planning to startup of the required controls was not sufficient. Other related activities, including project financing and obtaining a landfill permit for the scrubber waste, could also require more time than what the rule allowed. In addition, the short implementation period would require simultaneous outages of too many units to tie the new equipment into the existing systems, which would affect the reliability of the electrical grid.
- Implementation of controls to the required large number of units would cause shortages in the supply of critical industrial resources, especially boilermakers. An analysis performed by a commenter showed a shortfall in the supply of boilermaker labor during the construction period relevant to CAIR retrofits. This commenter anticipated that certain key variables would be greater in value than those used by EPA and based their analysis on higher SCR prices, EIA-projected higher natural gas prices and electricity demand factors, and more stringent boilermaker duty rates (boilermaker-year/MW) and availability factors.

Commenters who favored more stringent compliance deadlines argued that the required controls could be installed in less time and more controls could be built in early years. These commenters raised the following specific points in support of their concerns.

- The compliance deadlines for the two phases did not support the ozone and fine particulate ($PM_{2.5}$) attainment dates mandated by the CAA. The Phase I deadline should be accelerated to meet these attainment dates. Sufficient industrial resources, including boilermakers, would be available to support such an acceleration. While some commenters supported an earlier Phase I deadline of January 1, 2008, the others supported a deadline of January 1, 2009. Some of these commenters also suggested that the Phase I deadline be accelerated only for NO_X.
- The EPA's estimates for the boilermaker availability were too conservative. A boilermaker labor analysis performed by one commenter showed an adequate supply of this resource to support installation of all Phase I and II controls by the start of the first phase (by 2010), thereby eliminating the need for two phases.
- The time allowed for installing controls for Phase II was excessive. The initiation of this phase could be moved forward.

[71] The NO_X SIP Call Rule allowed approximately 3 1/2 years for implementation of all NO_X Controls.

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Several commenters supported EPA's assumptions used in support of the adequacy of the implementation period and resources to build the required CAIR controls. These assumptions included the overall construction schedule durations for SCR and FGD systems and boilermaker unit rates.

c. Responses

The EPA reviewed the above comments and performed additional research and analyses, including new IPM runs that incorporated higher SCR and natural gas costs and greater electric demand. We also found that more units had installed SCR under the NO_X SIP Call and other regulatory actions than what our records previously showed. This increase in the number of existing SCR installations was also incorporated into these IPM runs. In addition, the number of existing FGD installations was also revised slightly downward, for the same reason.

The revised IPM analyses for today's final action show that the amounts of controls that need to be put on for Phase I are 39.6 GW of FGD and 23.9 GW of SCR. These amounts represent a reduction from the estimates for the NPR. For Phase II, the amount of the required controls are 32.4 GW of FGD and 26.6 GW of SCR. These amounts represent an increase from the estimates for the NPR. The amounts shown for both phases reflect all retrofits required for the CAIR and base case (non-CAIR) policies. The retrofit projections for the base case policies are included, since some of the available boilermaker labor would be consumed in building these retrofits during the CAIR time-frame.

The EPA also contacted the International Brotherhood of Boilermakers (IBB), U.S. Bureau of Labor Statistics (BLS), and National Association of Construction Boilermaker Employers (NACBE) to verify its assumptions on boilermakers population, percentage of boilermakers available to work on the control retrofit projects, and average annual hours of boilermaker employment. Except for the boilermaker population, the information received as a result of these investigations validated EPA's assumptions. IBB also confirmed that the boilermaker population would at least be maintained at the current level of 26,000 members, during the period relevant to construction of CAIR retrofits. It did not want to forecast growth and historically has not done so. Therefore, instead of the 28,000 boilermaker forecasted population used in the NPR, we have conservatively used a boilermaker population of 26,000 for the final CAIR. A detailed discussion on these assumptions and the information received from these sources is available in the docket to this rulemaking as a technical support document (TSD), entitled ''Boilermaker Labor and Installation Timing Analysis, (docket no. OAR–2003–0053–2092).''

The responses to the most significant comments on these issues are summarized in the following sections.

i. Issues Related to Compliance Deadline Extension

(I) Adequacy of Phase I Implementation Period

Today's action initiates State activities in conjunction with EPA to set up the administrative details of CAIR. With the first phase compliance deadline of January 1, 2009, for NO_X and January 1, 2010, for SO_2, the affected sources would have approximately 3 3/4 and 4 3/4 years for the implementation of the overall requirements for this phase, respectively. The final SIPs would be submitted at the end of the first 18 months of these implementation periods. The remaining 2 1/4 and 3 1/4 years would be available for the sources to complete activities required for the procurement and installation of NO_X and SO_2 controls, respectively. For the reasons outlined below, EPA believes that these deadlines provide enough time to install the required Phase I controls.

(A) Engineering/Construction Schedule Issues

The EPA notes that, for CAIR, the States would finalize the SIPs in 18 months after the rule is signed, and that until then, the majority of sources required to install controls may not initiate activities that require commitment of major funds. However, some activities, such as planning, preparation of conceptual designs, selection of technologies, and contacts with equipment suppliers can be started or completed prior to the finalization of SIPs, at least for major sources expected to require longer implementation periods. In addition, other activities, such as permitting and financing can be started after the rule is finalized. This is based on the NO_X SIP Call experience.

After the SIPs are finalized, the sources would have approximately 2 1/4 and 3 1/4 years in which to complete purchasing, detailed design, fabrication, construction, and startup of the required NO_X and SO_2 controls, respectively. This assumes that activities, such as planning and selection of technologies, have already been started or completed, prior to the start of these 2 1/4- and 3 1/4-year periods. As discussed in the NPR proposal, EPA projects an average single-unit installation time of 21 months for SCR and 27 months for a scrubber. Our revised IPM analysis for the final rule shows that many facilities would install controls on multiple units (a maximum of six for SCR and five for FGD) at the same plant. We expect these facilities to stagger these installations to minimize operational disruptions.

The EPA also projects that SCRs and scrubbers could be installed on the multiple units in the available time periods of 2 1/4 and 3 1/4 years, respectively. The issues related to the availability of boilermakers and the ability of the plants requiring multiple-unit controls to stagger their installations during these periods are discussed later in this preamble.

As compared to projections in the NPR proposal, earlier signing of the final rule adds approximately three additional months to the overall implementation periods for SO_2 controls. Furthermore, EPA's projections for the final rule show fewer Phase I NO_X and SO_2 controls being added than the projections in the NPR proposal. Since the compliance deadline for NO_X has been moved up a year from the proposal, a three-month earlier rule promulgation provides more time for implementing SO_2 controls only. However, since it does allow use of critical resources, such as boilermakers, for SO_2 controls to be spread over a longer period of time, the net effect would be to make more of these resources available for both SO_2 and NO_X controls (as compared to a scenario where promulgation was not three months earlier). This is especially true since the implementation periods for both NO_X and SO_2 controls would start at the same time and the plants installing these controls would be competing for the same resources until January 1, 2009, the compliance deadline for NO_X. The EPA, therefore, believes that 2 1/4- and 3 1/4-year time periods provide reasonable amounts of time from the approval of State programs by September 2006, until the commencement of compliance deadlines for meeting the NO_X and SO_2 emission requirements.

Certain commenters have provided their own estimates of schedule requirements for installing the required controls. In some cases, these estimates are longer than those determined by EPA. For scrubbers, including spray dryer and wet limestone or lime type systems, the control implementation requirements provided by the commenters range from 30 to 54 months for the overall project and 18 to 36 months for the phase following

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equipment awards. In this case, the lowest 18-month schedule requirement cited applies to spray dryers, whereas the shortest schedule cited for wet scrubbers for the activities following the equipment awards is 24 months. For SCR, the control implementation requirements cited by the commenters range from 24 to 36 months for the overall project and 17 to 25 months for the phase following the equipment awards.

One commenter has pointed out that the construction schedule requirements for the FGD and SCR retrofit projects have shortened, because of the lessons learned from a significant number of such projects completed during the last few years. The EPA notes that a recent announcement for a new 485 MW limestone scrubber facility indicates a construction schedule duration (from equipment award to startup) of only 18 months.[72] This is well below the schedule requirement cited by the commenters for a wet limestone scrubber.

The EPA also notes that most of the commenters' schedule estimates are consistent with the time periods available for completing the CAIR-related NO_X and SO_2 projects. Some of the longer schedules submitted by commenters would exceed the CAIR Phase I dates. However, EPA considers these longer schedules to be speculative, as these commenters did not justify them. The major factors that influence schedule requirements include size of the installation, degree of retrofit difficulty, and plant location. The EPA does not expect these factors to make a difference of more than a few months between the schedule requirements of various installations. The commenters who have cited long schedule requirements that fall at the higher end of the above ranges have not provided any data to support the wide differences between their schedules and those proposed by others, including EPA. It should also be noted that EPA's schedules are based on information from several actual SCR and scrubber installations. Therefore, EPA cannot accept the excessive schedule requirements proposed by these commenters.

(B) Landfill Permit Issue

The EPA contacted several key States requiring FGD retrofits, to investigate the amount of time required to obtain a landfill permit for scrubber waste. We note that not all scrubber installations would require landfills, as some scrubber designs produce saleable waste products, such as gypsum.

Specifically, EPA contacted Georgia, Ohio, Indiana, Alabama, Pennsylvania, West Virginia, Tennessee, and Kentucky.[73] Except for Kentucky, all States indicated that their permit approval periods ranged from 12 to 27 months. Some of these States indicated that permit approval may require more time than 27 months, but only for the cases in which major landfill design issues persist or the permit applicant has not provided complete and proper information with the permit application.

The Kentucky Department of Environmental Protection indicated that, based on their historical records, the average permit approval period was 3 1/2 years. They also stated that the State was sensitive to an applicant's time restrictions and the permit approval times had varied depending on the level of urgency surrounding a permit application. They further confirmed that they would work with the industry to meet compliance deadlines, such as those required by CAIR, as efficiently as possible.

Based on the above investigations, EPA notes that the landfill permitting requirements quoted by all States fall well within the 4 3/4-year implementation period for Phase I. Also, landfill permitting activities as well as its design and construction can be accomplished, independent of the design and construction of the FGD system. The EPA, therefore, believes that landfill permitting is not a constraint for compliance with the rule.

(C) Project Financing Issue

Commenters representing small units or units owned by the co-operatives raised concerns that arrangement of financing for control retrofits could take long periods of time. However, EPA's projections show a larger portion of the smaller units installing controls only during the second phase. These projections also show that only a few co-operative units would require installation of controls. Therefore, EPA believes that the Phase I implementation periods of approximately 3 3/4 and 4 3/4 years for NO_X and SO_2 controls, respectively, provide enough time for completing the financing activity for all controls. Of course, if individual sources face difficulties in meeting deadlines to implement controls, they may use the allowance-trading provisions of CAIR to defer implementation of controls.

(D) Electrical Grid Reliability Issue

Based on available data for the NO_X SIP Call, approximately 68 GW of SCR retrofits were started up during the years from 2001 to 2003. This included approximately 42 GW of SCRs in 2003 alone, which exceeds the combined capacity of SCR and FGD retrofits for CAIR that we expect to be started up in any one year. The EPA projects that startup of the 23.9 GW of SCR and 39.6 GW of FGD capacity required for Phase I would be spread over a period of two years (2008 and 2009). The total capacity of units starting up in each year is therefore expected to be approximately 32 GW (half of the combined SCR and FGD capacity of 63.5 GW).

The NO_X SIP Call experience shows that outages required to complete installation of the large SCR capacity, especially during 2003, did not have an adverse impact on the electrical grid reliability. The EPA notes that the outage requirement for SCR usually exceeds that for scrubbers, since SCR is located closer to the boiler and it may be more intrusive to the existing equipment. As shown above, the CAIR retrofits are projected to include more scrubbers than SCRs and the capacity of these retrofits starting up in any one year is below the capacity of the NO_X SIP Call units that started up in 2003. Therefore, the overall outage requirement for CAIR would be less than that experienced for the NO_X SIP Call.

Based on published industry data, the planned outage times for coal-fired units from 2001–2002 (SCR buildup years) decreased by over two percent compared to the previous two years from 1998–1999.[74] The reduction in the overall outage time in the 2001–2002 period also shows that the SCR retrofits did not adversely affect the grid reliability. Therefore, EPA believes that the concern regarding electrical grid reliability is unwarranted for CAIR retrofits.

(II) Availability of Boilermaker Labor in Phase I

The EPA has performed several analyses to verify the adequacy of the available boilermaker labor for the installation of CAIR's Phase I controls. These analyses were not just based on using EPA's assumptions for the key

[72] ~~Reference:~~ Announcement by Wheelabrator Air Pollution Control Inc. for award of a wet limestone scrubber system for K.C. Coleman Generating Station, Western Kentucky Energy Corp., August 2, 2004, and other related documents. (docket no. OAR–2003–0053–1953)

[73] Summary of telephone calls with States to discuss landfill permit timing (docket no. OAR–2003–0053–1927).

[74] Reference: ''NERC, Generating Availability Data System: All MW Sizes—Coal-Fired Generation Report,'' *http://www.nerc.com/~filez/gar.html,* October 17, 2003.

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factors affecting the boilermaker availability, but also the assumptions suggested by commenters for these factors to determine how sure we could be on our key conclusions. If there was insufficient labor for the amount of air pollution controls that will need to be installed, the program would be in jeopardy. For instance, shortages in manpower could lead to high wage rates that could substantially increase construction costs for pollution controls and reduce the cost effectiveness of this program. During the peak of the NO_X SIP Call SCR construction period, the power industry did experience an increase in the SCR construction costs. One of the reasons cited for these higher costs was an increased demand for boilermaker labor. The EPA strongly wanted to avoid this possibility for CAIR. The EPA also wanted to be very sure that the levels of controls and timing of the program's start were appropriate. Therefore, EPA tended to make conservative assumptions and to test the sensitivity of key assumptions that were uncertain.

Boilermakers population, percentage of boilermakers available to work on the control retrofit projects, and average annual hours of boilermaker employment are some of the key factors that affect boilermaker availability. As discussed previously, EPA's assumptions on these factors were validated or revised through our discussions with IBB, BLS, and NACBE.

Two other key factors that also have an impact on boilermaker availability include the number of required SCR and FGD retrofits and boilermaker duty rates (boilermaker-year/MW, *i.e.*, the number of boilermaker years needed to install SCR or FGD on one MW of electric generation capacity). The EPA's projections for the required SCR and FGD retrofits are based on the IPM analyses performed for the final rule. The basis for the boilermaker duty rates used by EPA is a report prepared by EPA for the proposed Clear Skies Act, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies."

Some commenters have suggested use of EIA's projections of natural gas prices and electricity demand rates that are higher than EPA's projections used in the IPM analyses. Use of higher values for these parameters would increase the number of required control retrofits. While not agreeing with these commenters that EIA's projections should replace the data that EPA uses, we acknowledge that there is reasonable uncertainty concerning these assumptions and that addressing the uncertainty explicitly by considering EIA's alternative assumptions is prudent, given the importance of having sufficient labor resources to meet the program's requirements in 2010. Therefore, EPA has performed a sensitivity analysis to determine the required control retrofits resulting from the use of these EIA projections, and then used the increased amounts of the required control retrofits to determine their impacts on the boilermaker availability.

The EPA also received comments suggesting that the SCR costs used in our IPM analyses were below the levels experienced in recent SCR installations. We note that the SCR costs were revised in the IPM analyses performed for the final rule, to reflect recent industry experience. One commenter reported SCR capital costs that exceeded our revised costs. The EPA does not agree with these reported costs, as they are not supported by the overall cost data submitted by the commenter. However, to address the concern with the SCR costs in general, we have performed a sensitivity analysis to determine the impact of increasing the SCR capital and fixed O&M costs by 30 percent.

An increase in the SCR costs would affect the amounts of the required control retrofits. Table IV–12 shows the projected Phase I SCR and FGD retrofits for the above two alternate cases, based on using EIA's projections for natural gas prices and electricity demand rates and higher SCR costs.

TABLE IV–12.—IPM PROJECTIONS FOR TOTAL CAPACITIES OF FGD AND SCR RETROFIT PROJECTS FOR COAL-FIRED ELECTRIC GENERATION UNITS FOR CAIR PHASE I USING EPA AND COMMENTER ASSUMPTIONS

Retrofit type	EPA base case assumptions	EIA projections [1]	EIA projections and higher SCR costs [2]
CAIR FGD, GW	37	45.4	47.9
Non-CAIR FGD, GW	2.6	3.7	Included Above
CAIR SCR, GW	18.2	20.6	25.2
Non-CAIR SCR, GW	5.7	4.6	Included Above

[1] The required control retrofits shown are based on using EIA projections for natural gas prices and electricity demand rates.
[2] The required control retrofits shown are based on using EIA projections for natural gas prices and electricity demand rates as well as 30 percent higher SCR capital and fixed O&M costs.

As shown in Table IV–12 above, the alternate case using just the EIA's projections for natural gas prices and electricity demand rates requires the largest amounts of control retrofits. Therefore, a boilermaker availability analysis was performed for just this case.

One commenter has suggested use of higher boilermaker duty rates for both SCR and FGD retrofits, based on an industry survey they had conducted. Use of higher duty rates would result in more boilermakers being needed to install the controls. Table IV–13 shows the boilermaker duty rates used by EPA as well as those suggested by this commenter.

TABLE IV–13.—BOILERMAKER DUTY RATES FOR SCR AND FGD SYSTEMS FOR COAL-FIRED ELECTRIC GENERATION UNITS

Source	FGD	SCR
EPA's estimate, boilermaker-year/MW	0.152	0.175
Commenter-suggested, boilermaker-year/MW [1]	0.269	0.343

[1] The duty rate values shown are average values calculated by using the FGD and SCR correlations provided by the commenter along with the MW size of individual units projected by the IPM to require FGD or SCR controls for Phase I of CAIR.

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Our review of the limited supporting information submitted by the commenter about their survey for these duty rates shows that they are based on data from a small number of installations and represent scope of work at each power plant that is well above the average installation conditions used in determining the duty rates used by EPA. Therefore, EPA considers these commenter-suggested duty rates to represent the upper end of the range of values that would be expected for the SCR and FGD controls under consideration. This is also supported by the average duty rate (0.199) submitted by one other commenter for installing FGDs, which is well below the average duty rate (0.269) suggested by the first commenter. However, EPA also notes that the duty rate suggested by the second commenter is higher than that (0.152) used by EPA.

The EPA conducted the boilermaker analysis for the final rule using alternative assumptions for boilermaker duty rates. These alternative assumptions yield a range of estimates of the amount of control that could feasibly be installed. In keeping with EPA's desire to be very sure that there is sufficient boilermaker labor available during the CAIR's Phase I construction period, the Agency has considered the most stringent duty rates suggested by the first commenter, as well as other duty rates (see Table IV–13), in analyzing the impact on the boilermaker availability. The EPA considers this to be a bounding analysis in which the estimates based on the most stringent duty rates reflect conditions with the highest retrofit difficulty level that EPA could realistically expect to occur. We expect that the average boilermaker duty rates applicable to the overall boiler population required to retrofit controls under this rule would not fall outside of the values used by EPA and those suggested by the first commenter.

In the NPR, only the union boilermakers belonging to the IBB were considered in the EPA's availability analysis. Some commenters have pointed out that additional sources of boilermakers will be available for CAIR. Two such sources include non-union and Canadian boilermakers. IBB has confirmed that 1,325 Canadian boilermakers were brought in to support the NO_X SIP Call SCR work in 2003. The EPA also projects that approximately 15 percent of FGDs and 43 percent of SCRs will be installed for Phase I in the traditionally non-union States and believes there will be nonunion labor available in these States. One source has confirmed that a substantial amount of SCR retrofit work during the 2000–2002 period was executed by non-union labor.[75] Based on these data, we have conservatively assumed that 1,000 boilermakers from Canada will be available and 10 percent of the retrofits would be installed by non-union boilermakers for Phase I.

Based on EPA data, an average 32 GW of new gas-fired, combined cycle generating capacity was being added annually, during the NO_X SIP Call SCR construction years of 2002 and 2003. A substantial number of boilermakers were involved in the construction of these gas-fired projects. Since projections for the timeframe relevant to CAIR retrofits show only a small amount of new electric generating capacity being added, the number of boilermakers involved in the building of new plants would be smaller and more of the boilermaker population would be available to work on the Phase I retrofits. As pointed out by one commenter, the boilermakers available due to this projected drop in the building of new generation capacity represents a third additional source of boilermakers for CAIR.

The EPA projects only an insignificant amount of new coal-fired generating capacity being added during Phase I. The most recent EIA's projections also do not show any new coal fired capacity being added between 2007 and 2010, the timeframe relevant to boilermaker-related construction activities for CAIR.[76] However, EPA's projections do show approximately 15 GW of new or repowered gas-fired capacity being added, during 2007–2010. The EIA's projections for new gas-fired capacity addition during Phase I are well below those of EPA's. We used the more conservative EPA projections for new generating capacity additions and the gas-fired capacity additions during the NO_X SIP Call period to estimate the additional boilermaker labor that would become available for the Phase I retrofits. This estimate shows that approximately 28 percent more boilermakers would be available to work on the CAIR retrofits, because of a slowdown in the construction of new power plants.[77]

In the boilermaker availability analyses performed by EPA, the required boilermaker-years were determined for each case, based on the amounts of SCR and FGD retrofits being installed and the pertinent boilermaker availability factors and duty rates. The required boilermaker-years were then compared to the available boilermaker years to verify adequacy of the boilermaker labor. All sources of boilermakers were considered in these analyses, including the union boilermakers and the boilermakers from the three additional sources discussed previously.

The EPA's boilermaker availability analyses firmly support CAIR's Phase I requirements. Using EPA's projections of FGD and SCR retrofits installed for Phase I and EPA's assumptions for boilermaker duty rates, there are ample boilermakers available with a large contingency factor to support the predicted levels of CAIR retrofits. For the most conservative analysis using the boilermaker duty rates suggested by one commenter and the EIA's projections for natural gas prices and electricity demand rates, there are sufficient boilermakers available with a contingency factor of approximately 14 percent.

In the NPR proposal, EPA estimated that a contingency factor of 15 percent was available to offset any increases in boilermaker requirements due to unforeseen events, such as sick leave, time lost due to inclement weather, time lost due to travel between job-sites, inefficiencies created due to project scheduling issues, etc. The EPA had considered this 15 percent contingency factor to be adequate for these unforeseen events. We also note that EPA did not receive any comments suggesting a need for a higher contingency factor.

The EPA also notes that the above boilermaker labor estimates have not considered the benefits of the experiences gained by the U.S. construction industry from the recent buildup of large amounts of air pollution controls, including the NO_X SIP Call SCRs. As pointed out by one commenter, such experiences include use of modular construction, which can result in a significant reduction in the required boilermaker labor for CAIR retrofits. Also, as a result of this controls buildup, an increased number of experienced designers and construction personnel have become available to the industry. Some of these benefits may be offset by factors, such as the increased level of retrofit difficulty expected for the CAIR retrofits, especially for the small size units. However, we believe that the net effect of this experience is a more efficient use of the boilermaker labor in the construction of the air

[75] Reference: ''Email from Institute of Clean Air Companies,'' September 15, 2004 (See Appendix B, Boilermaker Labor Analysis and Installation Timing).

[76] Reference: ''Annual Energy Outlook 2005 (Early Release), Tables A9 and 9,'' December 2004, *http://www.eia.doe.gov/oiaf/aeo/index.html*.

[77] TSD, ''Boilermaker Labor and Installation Timing Analysis,'' (Docket no. OAR–2003–0053–2092).

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pollution control retrofits projects. Unfortunately, EPA cannot quantify the value of this experience in determining its overall impact on boilermaker requirements.

Therefore, EPA considers the 14 percent contingency in the available boilermaker-years for the above bounding analysis using commenter-suggested assumptions to be adequate.

ii. Issues Related to Compliance Deadline Acceleration

(I) Acceleration of Phase I Compliance Deadline

As a result of EPA's review of the comments received and further investigations conducted by the Agency for the final rule, the compliance deadline for implementing Phase I NO_X controls has been moved up by one year. We believe that the affected plants would have sufficient time with this change to meet the CAIR requirements associated with NO_X emissions, as long as the compliance deadline for implementing SO_2 controls is not changed. The EPA does not agree that accelerating the originally proposed Phase I compliance deadline of January 1, 2010, for implementing both NO_X and SO_2 controls is possible. These issues are discussed below.

(A) Two-Year Phase I Acceleration for NO_X and SO_2 Controls

With today's final action and allowing 18 months for the SIPs, sources installing controls would have approximately $3^1/_4$ years for implementing the rule's requirements. Some commenters suggested moving Phase I forward by 2 years, with a new compliance deadline of January 1, 2008, which would reduce the implementation period to $1^1/_4$ years. It is recognized that sources generally would not initiate any implementation activities that require major funding, before the final SIPs are available.

The EPA's projections show that, for SCR installation on one unit, an average 21-month schedule is required to complete purchasing, construction, and startup activities. For the same activities for FGD, an average 27-month schedule is required. As can be seen, the total time required for just one SCR or FGD installation exceeds the $1^1/_4$-year implementation period available for Phase I, if the compliance deadline is moved to January 1, 2008.

(B) One-Year Phase I Acceleration for NO_X and SO_2 Controls

If the Phase I compliance deadline for both NO_X and SO_2 controls is moved up by 1 year, the affected facilities would have $2^1/_4$ years or 27 months to complete installation of these controls. As discussed in the preceding section, FGD installation on one unit requires an average 27-month schedule to complete purchasing, construction, and startup activities.

The sources installing controls on more than one unit at the same facility would likely stagger the outage-related activities, such as final hookup of the new equipment into the existing plant settings and startup, to minimize operational disruptions and avoid losing too much generating capacity at one time. The EPA projects that an average 2-month period is required to complete the outage construction activities and a 1-month period to complete the startup activities for FGD. Therefore, if back-to-back outages are assumed for a plant installing FGD on just two units, the 27 months needed to install FGD on the first unit and an additional 3 months needed for outage activities on the second unit would result in an overall schedule requirement of 30 months. This 30-month schedule exceeds the available 27-month implementation period, if the compliance deadline is moved up by 1 year. For plants installing FGD controls on more than two units and performing hookup construction and startup activities in back-to-back outages, an additional 3 months would be added to the 30-month schedule requirement for each additional unit.

The EPA notes that certain plants installing multiple-unit controls may be able to meet the compliance deadline requirement by using alternative approaches, such as simultaneous unit outages and purchase of allowances to defer installation of controls on some units. However, our projections for the final rule show that some facilities would be installing FGD controls on five multiple units at a single site. Moreover, these projections show 26 plants requiring FGD retrofit on more than one unit, which represents a major portion of the total number of plants required to install such controls under CAIR. We believe it would not be appropriate to expect this number of plants to resort to alternative means to accommodate such installations, such as simultaneous unit outages or purchasing of allowances.

For FGD retrofits, some plants would be required to obtain solid waste landfill permits. As discussed previously, the time required to obtain these permits could range from one to $3^1/_2$ years. With the compliance deadline moved up by one year, the overall implementation period would be reduced from $4^3/_4$ to $3^3/_4$ years. For those plants subjected to a $3^1/_2$-year permit approval period, only 3 months would be available to prepare the permit applications at the beginning of the compliance period and to prepare the landfill area for accepting the waste after permit approval. The EPA does not believe that 3 months is adequate for such activities. These plants would, therefore, need the $4^3/_4$-year implementation period to complete activities related to landfills associated with the FGD systems.

The EPA also performed an analysis to verify if the available boilermaker labor is adequate to support the January 1, 2009, compliance deadline for both NO_X and SO_2. This analysis was performed, using commenter-suggested boilermaker duty rates and EIA's assumptions for the natural gas prices and electricity demand rates. The results show that given these assumptions sufficient number of boilermakers will not be available and that there will be a shortfall of approximately 32 percent in the boilermakers available to support Phase I activities for this case.

Considering the constraints identified in the above analyses for the FGD installation schedule requirements and boilermaker labor availability, EPA believes that it is not reasonable to move the Phase I compliance deadline for both NO_X and SO_2 caps to January 1, 2009.

(C) One-Year Phase I Acceleration for NO_X Controls Only

A 1 year acceleration would result in a compliance deadline of January 1, 2009, for installing Phase I NO_X controls. With this change, the affected sources installing these controls would have approximately $2^1/_4$ years for implementing the rule's requirements, following the approval of State programs. However the implementation period for installing FGD controls would still be at $3^1/_4$ years.

As shown previously, 21 months would be required to complete purchasing, construction, and startup of SCR on one unit. For multiple-unit installations with back-to-back unit outages for the tie-in construction and startup, the available $2^1/_4$-year implementation period would permit staggering of SCR installations on a maximum of three units (see the above referenced TSD). For a plant requiring SCR retrofit on more than three units, simultaneous outages of two units would become necessary. However, EPA notes that there are only six plants projected to require SCR installation on more than three units and, therefore, it is expected that simultaneous outages of two units at each of these plants would not have an adverse impact on the reliability of the electrical grid.

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In addition, the plants installing SCR on more than three units at the same site would have two other options to meet the rule's requirements, without having to resort to simultaneous two-unit outages. First, these plants would be able to defer installation of SCRs on some of the units by receiving allocated allowances or purchasing allowances from the 200,000-ton Compliance Supplement Pool being made available as part of CAIR.[78] Second, the outage activities for some of the units at these plants could be extended into the first quarter of 2009, which is beyond the compliance deadline of January 1, 2009, since these units would not generate NO_X emissions during an outage and therefore not require any allowances to compensate for them. The EPA's projections show that, of the above six plants installing SCR on more than three units, four of them require SCR retrofits on four units each. If it is assumed that these four plants would perform outage activities on the fourth unit during the first quarter of 2009, there would only be two plants left that would be required to either purchase allowances or perform work during simultaneous outages.

The EPA also notes that the total schedule requirements for multiple-unit plants can be reduced further by performing some of the activities, especially those related to planning and engineering, prior to the 2¼-year period. Also, with the total installation time requirement for FGD being more than that for SCR, EPA expects the outages associated with most Phase I FGDs to take place after January 1, 2009. The overall impact of the outages taken for these SCR and FGD retrofits would, therefore, be minimized.

The EPA also performed an analysis to determine the impact of an 1-year acceleration in the NO_X compliance deadline on Phase I boilermaker labor requirements. Since the amounts of the required Phase I NO_X and FGD retrofits are not affected by this change, the overall boilermaker requirements for this phase will remain the same as previously reported for the case with the same compliance deadline for both NO_X and SO_2. However, with the new NO_X compliance deadline, installation of all NO_X retrofits would have to be completed by January 1, 2009, and some of the FGD construction work requiring boilermakers would also be done during this period. The EPA assumed that, along with completing installation of all SCRs, 35 percent of the boilermaker labor required to install all FGDs would be used in the period prior to January 1, 2009. This is a conservative assumption, since the amount of boilermaker labor used for this period would be greater than 50 percent of the total Phase I boilermaker labor requirement. The analysis performed by EPA shows that sufficient boilermakers would be available with a contingency factor of approximately 14 percent to install all SCR controls and 35 percent of the FGD retrofit work by January 1, 2009. This analysis is based on the most conservative assumptions, using the boilermaker duty rates suggested by one commenter and the EIA's projections for natural gas prices and electricity demand rates. Based on the above analyses, EPA believes that moving the compliance deadline for Phase I for both NO_X and SO_2 is not practical. However, a 1-year acceleration in the compliance deadline for NO_X only is feasible. Since EPA is obligated under the CAA to require emission reductions for obtaining NAAQS to be achieved as soon as practicable, we have based the final rule on two separate Phase I compliance deadlines of January 1, 2009, and January 1, 2010, for NO_X and SO_2, respectively.

(II) Implementing All Controls in Phase I

The EPA proposed a phased program with the consideration that for engineering and financial reasons, it would take a substantial amount of time to install the projected controls. This program would require one of the most extensive capital investment and engineering retrofit programs ever undertaken in the U.S. for pollution control. The capital investment for pollution control for CAIR that would be installed by 2015 is estimated to be approximately 15 billion dollars. By 2015, close to 340 control unit retrofits will occur. This is occurring at a time when the industry also faces another major infrastructure challenge—upgrading transmission capacity to make the grid more reliable and economic to operate. This also will cost tens of billions of dollars.

The proposed program's objective was to eliminate upwind states' significant contribution to downwind nonattainment, providing air quality benefits as soon as practicable. A phased approach was also considered necessary because more of the difficult-to-retrofit and finance, smaller size units would be included in the second phase, which would allow them to complete activities necessary for implementing the required controls as well as provide them an opportunity to benefit from the lessons learned during the first phase.

In general, environmental controls resulting from legislative or regulatory actions are applied to those units first that offer superior choices from constructability and cost-effectiveness standpoints. Experience gained by the industry from these installations can then be used to develop innovative solutions for any constructability issues and to improve cost effectiveness, as these technologies are applied to harder-to-control units. The EPA believes that this phenomenon applies to the application of the SCR and FGD technologies at coal-fired power plants.

In the last few years, SCR and FGD systems have been added to several existing coal-fired units, under the NO_X SIP Call and Acid Rain Program. These were mainly large units that had features, such as spacious layouts, amenable to the retrofit of the new air pollution control equipment. The units installing controls during Phase I of CAIR would, in general, be smaller in size and would offer relatively more difficult settings to accommodate the new equipment. These units would certainly benefit from the experience the industry has gained from the installations completed in recent years.

A large portion of the units (47 percent) projected to implement controls during the second phase consists of even smaller units, less than 200 MW in size. Compared to larger units, the retrofits for these smaller units would be more difficult to plan, design, and build. Historically, smaller units have been built with less equipment redundancy, smaller capacity margins, and more congested layouts. It is likely, therefore, to be more difficult and require additional design efforts to accommodate the new equipment into the existing settings for the smaller units. Use of lessons learned by firms constructing these units from the previous installations, including those to be built during the first phase, would help streamline this process and maintain the cost effectiveness of these installations. Moving a large portion of the retrofits required for these smaller units to the second phase also provides more time to complete the required retrofit activities.

Because EPA's projections for the second phase include a large proportion of smaller units, the total number of units requiring NO_X and SO_2 controls exceeds that in the first phase (186 vs. 153). Requiring an acceleration of the second phase controls to be completed in the first phase would, therefore, more than double the number of retrofits

[78] The 200,000-ton Compliance Supplement Pool is apportioned to each of the 23 States and the District of Columbia that are required by CAIR to make annual NO_X reductions, as well as the 2 States (Delaware and New Jersey) for which EPA is proposing to require annual NO_X reductions.

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required for the first phase from 153 to 339. Based on data available from EPA and other sources, the industry completed 95 SCR installations for the NO_X SIP Call in 2002 and 2003. If the 2004 projections for the NO_X SIP Call are added to this number, the total number of SCR retrofits over the 2002–2004 period would be 140. This is less than half the number that would be required for CAIR during a similar period, if the Phase II requirements are implemented along with the Phase I requirements. Also, the combined capacity for FGD and SCR retrofits required for Phase I would be 122.5 GW, which is approximately 57 percent greater than the installed SIP-Call SCR capacity for the 2002–2004 period. Such a change in the rule would therefore amount to imposing a requirement over the power industry that is significantly more demanding and burdensome than what the industry was required to do under the NO_X SIP Call rule.

The EPA notes that critical resources other than the boilermakers are needed for the installation of SCR and FGD controls, such as construction equipment, engineering and construction staffs belonging to different trades, construction materials, and equipment manufacturers. Some commenters, based on their experience with NO_X SIP Call, also pointed out that the requirement for some of these resources, especially construction equipment (*e.g.*, large cranes used to mount SCR and scrubber vessels above ground), construction materials, equipment manufacturing shop capacities, and engineering and construction management teams overseeing these projects, is affected directly by the number of installations. The greater the requirement is to install a large number of retrofits by 2010, the greater would be the need for all these resources, which would be limited in the short term, as demands from equipment vendors, project teams, and material suppliers ramp up. In the NO_X SIP Call, this led to shortages and bottlenecks in projects in certain areas, causing increased project times and costs. The EPA wants to avoid creating a similar situation by requiring too much at once.

The EPA has also acknowledged the increase in SCR costs during the NO_X SIP Call implementation period, most likely due to an increase in construction costs (resulting from increased demand for boilermaker labor) and steel prices. The EPA has revised its estimates of SCR capital costs in the IPM runs for the final rule and believes the conservatism in its FGD capital costs also accounts for this factor.

The EPA believes that moving the Phase II requirements to the Phase I period could cause near-term shortages in some of the critical resources. This would further increase compliance costs and could remove the highly cost-effective nature of these controls and lead to a greater demand for natural gas.

In addition to the above, financing a large amount of controls for Phase I may prove challenging, especially for the coal plants owned by deregulated generators. As discussed later in this section, such generators are continuing to face serious financial challenges, and many have below investment grade credit ratings. This significantly complicates the financing of costly retrofit controls. Such plants would also not have the certainty of regulatory recovery of investments in pollution control, and would have to rely on the market to recover their costs. Having a second phase cap would allow these companies additional time to strengthen their finances and improve their cash flow.

In the interest of being prudent in evaluating the need to phase in the program, EPA also performed an analysis to determine if the available boilermaker labor would be adequate to support installation of all Phase I and II controls in 2010. This analysis was conservatively based on using commenter-suggested boilermaker duty rates and EIA's projections for gas prices and electricity demand rates. The results show that a sufficient number of boilermakers will not be available and that there will be a shortfall of approximately 25 percent in the boilermakers available to support Phase I activities for this case.

Based on the above analyses, EPA believes that implementation of controls for both phases in Phase I is impractical. We also believe that it is prudent and reasonable in requiring the industry to undertake this massive retrofit program on a two-phase schedule, to be largely completed in less than a decade.

(III) Acceleration of Phase II Compliance Deadline

The EPA does not believe that acceleration of the compliance deadline for the second phase is reasonable. As pointed out earlier, a large portion of the units projected to install controls during the second phase consists of small units, less than 200 MW in size. Due to the issues related to financing of the retrofit projects for some of these units and considering that planning and designing of controls for these units is likely to take longer, EPA does not consider the schedule acceleration to be appropriate.

The EPA notes that Phase I of CAIR is the initial step on the slope of emissions reduction (the glide-path) leading to the final control levels. Because of the incentive to make early emission reductions that the cap-and-trade program provides, reductions will begin early and will continue to increase through Phases I and II. The EPA, therefore, does not believe that all of the required Phase II emission reductions would take place on January 1, 2015, the compliance deadline. These reductions are expected to accrue throughout the implementation period, as the sources install controls and start to test and operate them.

The EPA also notes that the 5-year implementation period for Phase II is consistent with other regulations and statutory requirements, such as title IV for SO_2 and NO_X controls. In addition, some commenters have cited a need for a 6-year period for obtaining financing for plants owned by the co-operatives. These facilities are likely to commit funds for major activities, only after financing has been obtained. Therefore, for such facilities, a period of approximately four years would be available for procuring, installing, and startup activities, assuming that the financing activities were started right after the rule is finalized. Since the plants owned by co-operatives are usually small in size, they are likely to require and be benefitted by the extra time allowed to them by this four-year implementation period.

The EPA also performed an analysis to verify adequacy of the available boilermaker labor for pollution control retrofits the power industry will install to comply with the Phase II CAIR requirements. A 36-month construction period requiring boilermakers was conservatively selected for this analysis. Based on the IPM analysis for the final rule, conservatively, the power industry will build 27.5 GW of FGD and 26.6 GW of SCR retrofits for compliance with lower emission caps that go into effect for NO_X and SO_2 in 2015. The analysis was based on using EIA's projections for the natural gas prices and electricity demand rates and the commenter-suggested boilermaker duty rates. The results show availability of ample boilermakers with a contingency factor of 46 percent to support Phase II activities.

The EPA notes that the retrofits that will occur in Phase II will be smaller, more numerous, and more challenging, since the easiest controls will likely be installed in Phase I. Therefore, having a greater contingency factor (as we do) is warranted. This is further supported when the uncertainty in predicting the

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construction activities in the areas outside of air pollution controls is considered. Notably after 2010, the excess generation capacity that we have today is no longer expected to be present and there may be a shift towards a requirement for increasing generation capacity. Increased construction of new power plants will have a direct impact on the availability of boilermakers for the Phase II controls. The EPA believes that a higher contingency factor for Phase II is desirable to ensure that the industry will succeed in getting the required reductions at the required time.

Any acceleration of the Phase II compliance deadline will also cause an appreciable reduction in the above estimated contingency factor for boilermaker labor. For example, based on EPA analysis, an acceleration of one year is projected to reduce this contingency factor to only about one percent. Therefore, EPA believes that acceleration of the Phase II compliance deadline cannot be justified.

3. Assure Financial Stability

The EPA recognizes that the power sector will need to devote large amounts of capital to meet the control requirements of the first phase. Furthermore, over the next 10 years, the power sector is facing additional financial challenges unrelated to environmental issues, including economic restructuring impacts, investments related to domestic security and investments related to electrical infrastructure. Among the consideration of other factors, EPA believes it is important to take into account the ability of the power sector to finance the controls required under CAIR. A detailed assessment of the status of the financial health of the U.S. Utility Industry, particularly of the unregulated sector is offered in the TSD, ''U.S. Utility Industry Financial Status and Potential Recovery.''

Commenters have noted that they appreciate EPA's growing realization that many companies may have difficulty securing financing, and the agency's establishment of a two-phase reduction program on both technical and financial grounds.

Utilities and non-utility generating companies have felt significant financial pressure over the past 5 years. The years 2000 and 2001 saw the escalation and fallout from the California energy crisis, the bankruptcy of Enron, and a massive building program, largely on the side of the merchant generating sector. Subsequent low power margins and large debt obligations have led to a significant number of credit downgrades of utilities and power generators and the bankruptcy of coal-generating merchant companies. According to Standard and Poor's, a leading provider of investment ratings, there were almost ten times more downgrades of utility credit in 2002 and 2003 than there were upgrades. While more recently the sector has stabilized, a significant number of owners of coal-fired capacity in the CAIR region, particularly those with deregulated capacity, are still at below investment-grade credit ratings.

In general, EPA believes that regulated plants, given appropriate regulatory requirements, should not face significant financial problems meeting their obligations under CAIR. While EPA recognizes that issues such as the expiration of rate caps and the time lags associated with regulatory approval and recovery may provide cash flow challenges, regulated electricity rates are generally seen as a positive factor in credit ratings, as entities are allowed a recovery on prudent investment through rate cases (and, in some jurisdictions, the recovery of allowance expenditures through fuel adjustment clauses).

Deregulated coal capacity (operating in an environment of market prices rather than electricity rates set by regulators) has no such guarantees, and would need to recover investments in pollution control from market prices (which in many cases are not set by coal units). Additionally, deregulated entities, because of their more aggressive building and borrowing strategies and reliance on market prices (which now reflect the current capacity overbuild), have faced more significant financial difficulties (including a number of bankruptcies) and are currently in a weaker position financially.[79] A number of firms that have avoided financial distress in the near term have done so by renegotiating their pending debt, postponing payment. A good portion of this debt is of a shorter-term nature, and will be coming due in the next five years.

Such financial difficulties increase the cost of capital necessary for capital expenditures and affect the availability of such capital, making required controls more expensive. Recent financial troubles have been cited as the reason for the deferment or cancellation of pollution control expenditures. Should interest rates rise in the future, it will become more difficult and costly for utilities seeking financing.

These problems impact a significant segment of coal generators, as deregulated coal capacity makes up about a third of all U.S. coal capacity and almost 90 percent of this deregulated capacity would be affected by CAIR requirements.

Given the lead times needed to plan and construct such equipment, as well as the financial uncertainty many of the plant owners are confronting, companies may find it difficult to install controls at their plants too quickly. The EPA believes that the choice of timing of the emission caps in CAIR would allow firms time to improve their current and near-term financial difficulties (through reorganization, mergers, sales, etc.). Phasing in the more stringent emission caps by 2015 would also spread investment requirements and resulting cash flow demands, rather than forcing firms to finance a large spike in investments in a very short time period, while they are still trying to recover financially.

The timing of controls expected to be installed as a result of CAIR are similar to that noted in EPA's analysis of the Clear Skies proposal. The EPA looked in detail at the potential financial impact of the Clear Skies program (particularly focusing on the deregulated coal sector). The EPA found that some individual deregulated coal plants might be adversely affected, but on average such plants would actually experience a small financial improvement under Clear Skies. Baseload deregulated coal plants would benefit from even slight increases in the price of natural gas (units burning natural gas generally set the wholesale price of electricity on the margin in the regions where deregulated coal is located). These units would also be recipients of allocated allowances. Overall, the phased in nature of CAIR, the fact that most coal plants continue to be regulated and the fact that sources would also receive allowances, would all mitigate the financial impact of this rule.

The EPA believes that the timing requirements finalized today reflect a prudent and cautious approach designed to assure that the industry will succeed in implementing this program. The EPA believes that deferring the second phase to 2015 will provide enough time for companies to raise additional capital needed to install controls. Also, we believe that the implementation period should account (at least broadly) for the possibility that electricity demand or natural gas prices may increase more than assumed, and therefore that additional control equipment would be needed. Allowing until 2015 for implementation of the more stringent control levels in today's rule will provide more flexibility in the

[79] In fact, between nine and eleven (depending on the credit agency) of the twenty largest owners of deregulated coal capacity in the U.S. currently have below-investment-grade credit ratings.

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event of greater electricity demand and will ensure that power plants in the CAIR region will have the ability, both technical and financial, to make the pollution control retrofits required.

Currently, EPA is cooperating with the National Association of Regulatory Utility Commissioners (NARUC) in developing a menu of policy options and financial incentives for encouraging improved environmental performance for generation. A survey of a number of States was conducted as part of this effort, and policies such as pre-approval statutes for compliance plans, state income tax credits, accelerated depreciation, and special treatment of allowance transactions were cited as examples of such policies [80]. Such policies will ease some of the financial pressures of CAIR by providing greater regulatory certainty and lowering the effective costs of controls.

D. Control Requirements in Today's Final Rule

1. Criteria Used To Determine Final Control Requirements

The EPA's general approach to developing emission reduction requirements—basing the requirements on the application of highly cost-effective controls—was adopted in the NO_X SIP Call and has been sustained in court. In the NPR, the Agency proposed this approach for developing SO_2 and NO_X emission reduction requirements. The majority of commenters accepted this basic approach for determining reduction requirements. Some commenters did suggest other approaches, however, as discussed above.

Many commenters suggested that the CAIR regionwide SO_2 and NO_X control levels should be more or less stringent than the levels proposed in the NPR. The EPA has determined that the control levels that we are finalizing today are highly cost-effective and feasible, and constitute substantial reductions that address interstate transport, at the outset of State and EPA efforts to bring about attainment of the $PM_{2.5}$ NAAQS (EPA believes that most if not all States will obtain CAIR reductions by capping emissions from the power sector). Today, EPA finalizes the use of both average and marginal cost effectiveness of controls as the basis for determining the highly cost-effective amounts.

[80] The survey results are in ''A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities: Policy and Regulatory Initiatives,'' at *http://www.naruc.org/displayindustryarticle.cfm?articlenbr=21826.*

In the CAIR NPR, EPA proposed criteria for determining the appropriate levels of SO_2 and NO_X emissions reductions, and stated that EPA considered a variety of factors in evaluating the source categories from which highly cost-effective reductions may be available and the level of reduction assumed from that sector (69 FR 4611). The EPA has reviewed comments on its NPR, SNPR and NODA and conducted further analyses with respect to the proposed criteria, and is finalizing its control requirements in today's action. Following is a brief summary of EPA's conclusions based on the criteria.

The availability of information, and the identification of source categories emitting relatively large amounts of the relevant emissions, are two criteria used in EPA's evaluation of the CAIR program. In the NPR, EPA stated that EGUs are the most significant source of SO_2 emissions and a very substantial source of NO_X in the affected region, and further stated that highly cost-effective control technologies are available for achieving significant SO_2 and NO_X emissions reductions from EGUs. We requested comment on sources of information for emissions and costs from other sectors (69 FR 4610). A detailed discussion regarding non-EGU sources is provided above. The EPA has not received additional information that would change its proposed control strategy.

Another criterion is the performance and applicability of control measures. The NPR included a detailed discussion of the performance and applicability of SO_2 and NO_X control technologies for EGUs. In particular, EPA discussed FGD for SO_2 removal and SCR for NO_X removal, both of which are fully demonstrated and available pollution control technologies on coal-fired EGU boilers (69 FR 4612). None of the commenters provided information that differed from EPA's assessment of the performance of these control measures. In addition, the commenters generally supported EPA's assumptions on the applicability of these controls.

The cost effectiveness of control measures is another criterion used in EPA's analysis. As discussed in detail above, EPA determined that the proposed control levels are highly cost-effective, and is finalizing the levels in today's action. The EPA used IPM to analyze the cost effectiveness of the proposed and final CAIR control requirements. IPM incorporates assumptions about the capital costs and fixed and variable operations and maintenance costs of control measures for EGUs. Several commenters suggested that the SCR control cost assumptions that we used in IPM analysis for the NPR were too low. Consequently, we increased the SCR control cost assumptions in IPM and conducted cost effectiveness modeling for the final control requirements using these updated costs.[81] Commenters generally supported our FGD control costs assumptions, which are largely unchanged from the NPR modeling to the modeling for today's final rule.

And finally, EPA considered engineering and financial factors that affect the availability of control measures. The EPA conducted a detailed analysis of engineering factors that affect timing of control retrofits, including an evaluation of the comments received. The EPA's analysis supports its compliance schedule, a two-phase emissions control program with the final phase commencing in 2015, and with a first phase commencing in 2010 for SO_2 reductions and in 2009 for NO_X reductions. Further, EPA's analysis demonstrates that it would not be realistically possible to start the program sooner, or to impose more stringent emissions caps in the first phase.

Based on EPA's review of comments and analysis, EPA determined that the proposed control requirements are reasonable with respect to engineering factors. As discussed above, EPA also considered how to avoid creating financial instability for the affected sector, and how to ensure the capital needed for the required controls would be readily available. Assuming States choose to control EGUs, the power sector will need to devote large amounts of capital to meet the CAIR control requirements.

The EPA explained that implementing CAIR as a two-phase program, with the more stringent control levels commencing in the second phase, will allow time for the power sector to address any financial challenges. The EPA's evaluation of engineering and financial factors supports the decision to implement CAIR as a two-phase program, with the final (second) compliance level commencing in 2015 and a first phased-in level starting in 2010 for SO_2 reductions and in 2009 for NO_X reductions. A description of the final CAIR control requirements follows.

[81] Detailed documentation of EPA's IPM update, including updated control cost assumptions, is in the docket. The SCR control cost assumptions were presented in a peer-reviewed paper by Sikander Khan and Ravi Srivastava, ''Updating Performance and Cost of NO_X Control Technologies in the Integrated Planning Model,'' at the Combined Power Plant Air Pollution Control Mega Symposium, August 30–September 2, 2004, Washington, DC.

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2. Final Control Requirements

Today's final rule implements new annual SO_2 and NO_X emissions control requirements to reduce emissions that significantly contribute to $PM_{2.5}$ nonattainment. The final rule also requires new ozone season NO_X emissions control requirements to reduce emissions that significantly contribute to ozone nonattainment.

The final rule requires annual SO_2 and NO_X reductions in the District of Columbia and the following 23 States: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. (In the "Proposed Rules" section of today's action, EPA is publishing a proposal to include Delaware and New Jersey in the CAIR region for annual SO_2 and NO_X reductions.)

In addition, the final rule requires ozone season NO_X reductions in the District of Columbia and the following 25 States: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

The CAIR requires many of the affected States to reduce annual SO_2 and NO_X emissions as well as ozone season NO_X emissions. However, there are three States for which only annual emission reductions are required (Georgia, Minnesota and Texas). Likewise, there are five States for which only ozone season reductions are required (Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey). The following 20 States and the District of Columbia are required to make both annual and ozone season reductions: Alabama, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin.

Table IV–14 shows the amounts of regionwide annual SO_2 and NO_X emissions reductions under CAIR that EPA projects, if States choose to meet their CAIR obligations by controlling EGUs. Table IV–15 shows the amounts of regionwide ozone season NO_X emissions reductions under CAIR that EPA projects, if States choose to meet their CAIR obligations by controlling EGUs. If all affected States choose to implement these reductions through controls on EGUs, the regionwide annual SO_2 and NO_X emissions caps that would apply for EGUs are also shown in the Table IV–14, and ozone season NO_X caps for EGUs are in Table IV–15. Base case emissions levels for affected EGUs as well as emissions with CAIR are also shown in Table IV–14 and Table IV–15, based on IPM modeling.

The EPA is finalizing the regionwide EGU SO_2 emissions caps—if States choose to comply by controlling EGUs—as shown in Table IV–14 [82]. As indicated above, EPA identified SO_2 budget amounts, as target levels for further evaluation, by adding together the title IV Phase-II allowances for all of the States in the CAIR region, and making a 50 percent reduction for the 2010 cap and a 65 percent reduction for the 2015 cap. The EPA determined, through IPM analysis, that the resulting regionwide emissions caps (if all States choose to obtain reductions from EGUs) are highly cost-effective levels.

Also, EPA is finalizing the regionwide EGU annual and ozone season NO_X emission caps—if States choose to comply by controlling EGUs—as shown in Table IV–14 and Table IV–15.[83] As indicated above, EPA identified NO_X budget amounts, as target levels for further evaluation, through the methodology of determining the highest recent Acid Rain Program heat input from years 1999–2002 for each affected State, summing the highest State heat inputs into a regionwide heat input, and multiplying the regionwide heat input by 0.15 lb/mmBtu and 0.125 lb/mmBtu for 2009 and 2015, respectively. The EPA determined, through IPM analysis, that the resulting regionwide emissions caps (if all States choose to obtain reductions from EGUs) are highly cost-effective levels.

The emission reductions, EGU emissions caps, and emissions shown in Table IV–14 are for the 23 States and the District of Columbia that are required to make annual SO_2 and NO_X reductions for CAIR. (Table IV–14 does not include information for the five States that are required to make ozone season reductions only.)

The emission reductions, EGU emissions caps, and emissions shown in Table IV–15 are for the 25 States and the District of Columbia that are required to make ozone season NO_X reductions for CAIR. (Table IV–15 does not include information for the three States that are required to make annual reductions only.)

The EPA is requiring the CAIR SO_2 and NO_X emissions reductions in two phases. For States affected by annual SO_2 and NO_X emission reductions requirements, the final (second) phase commences January 1, 2015, and the first phase begins January 1, 2010 for SO_2 reductions and January 1, 2009 for NO_X reductions. For States affected by ozone season NO_X emission reductions requirements, the final (second) phase commences May 1, 2015 and the first phase starts May 1, 2009. Notably, the first phase control requirements are effective in years 2010 through 2014 for SO_2 and in years 2009 through 2014 for NO_X, and the 2015 requirements are for that year and thereafter.

TABLE IV–14.—FINAL RULE SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSION CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (23 STATE AND DC) FOR THE INTERIM PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR EGUS

(Million Tons) [84]

	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
First phase (2010 for SO_2 and 2009 for NO_X)				
SO_2	8.7	3.6	5.1	3.5
NO_X	2.7	1.5	1.5	1.2

[82] For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

[83] For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

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TABLE IV–14.—FINAL RULE SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSION CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (23 STATE AND DC) FOR THE INTERIM PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR EGUS—Continued

(Million Tons) [84]

	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
Sum	11.4	NA	6.6	4.8
Second Phase (2015 for SO_2 and NO_X)				
SO_2	7.9	2.5	4.0	3.8
NO_X	2.8	1.3	1.3	1.5
Sum	10.6	NA	5.3	5.3

Notes: Numbers may not add due to rounding.

1. The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–14. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.
2. The District of Columbia and the following 23 States are affected by CAIR for annual SO_2 and NO_X controls: AL, FL, GA, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI.
3. The 2010 SO_2 emissions cap applies to years 2010 through 2014. The 2009 NO_X emissions cap applies to years 2009 through 2014. The 2015 caps apply to 2015 and beyond.
4. Due to the use of the existing bank of SO_2 allowances, the estimated SO_2 emissions in the CAIR region in 2010 and 2015 are higher than the emissions caps.
5. Over time the banked SO_2 emissions allowances will be consumed and the 2015 cap level will be reached. SO_2 emissions levels can be thought of as on a flexible ''glide path'' to meet the 2015 CAIR cap with increasing reductions over time. The annual SO_2 emissions levels in 2020 with CAIR are forecasted to be 3.3 million tons within the region encompassing States required to make annual reductions, an annual reduction of 4.4 million tons from base case levels.

TABLE IV–15.—FINAL RULE NO_X OZONE SEASON BASE CASE EMISSIONS, EMISSIONS CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE OZONE SEASON NO_X REDUCTIONS (25 STATES AND DC) FOR THE INTERIM PHASE (2009) AND FINAL PHASE (2015) FOR ELECTRIC GENERATION UNITS

(Million Tons) [85]

Ozone Season NO_X				
Phase	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
2009	0.7	0.6	0.6	0.1
2015	0.7	0.5	0.5	0.2

Notes:

1. The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–15. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.
2. The District of Columbia and the following 25 States are affected by CAIR for ozone season NO_X controls: AL, AR, CT, DE, FL, IA, IL, IN, KY, LA, MA, MD, MI, MO, MS, NJ, NY, NC, OH, PA, SC, TN, VA, WV, WI.
3. The 2009 NO_X emissions cap applies to years 2009 through 2014. The 2015 cap applies to 2015 and beyond.

Table IV–16 shows the estimated amounts of regionwide annual SO_2 and NO_X emissions reductions that would occur if EPA finalizes its proposal to find that Delaware and New Jersey contribute significantly to downwind $PM_{2.5}$ nonattainment, and if all affected States choose to control EGUs (the proposal is published in the ''Proposed Rules'' section of today's action). In that case, the estimated regionwide annual SO_2 and NO_X emissions caps that would apply for EGUs are as shown in Table IV–16. Annual base case emissions levels for EGUs in the CAIR region (including Delaware and New Jersey) as well as emissions with CAIR are also shown in the Table, based on IPM modeling. If EPA finalizes its proposal to include Delaware and New Jersey for $PM_{2.5}$ requirements, then the ozone

[84] Table IV–14 includes regionwide information for the 23 States and DC that are required by CAIR to make annual emission reductions. It does not include information for the 5 CAIR States that are required to make ozone season reductions only. The CAIR requires NO_X emission reductions in a total of 28 States and DC. For 20 States and DC, both annual and ozone season NO_X reductions are required. For 3 States only annual reductions are required, and for 5 States only ozone season reductions are required. The total projected NO_X emission reductions that will result from CAIR—if all States control EGUs—include the annual reductions shown in Table IV–14 (for 23 States and DC) plus the ozone season reductions in the 5 States required to make ozone season reductions only. The EPA projects the total NO_X reductions, in all 28 CAIR States and DC, to be 1.2 million tons in 2009 and 1.5 million tons in 2015. Note that the values in this table represent the final CAIR policy and differ slightly from the values in the RIA (which were based on an earlier and slightly different IPM) (see more detailed discussion both earlier in this section and in the RIA).

[85] Table IV–15 shows regionwide information for the 25 States and DC that are required to make ozone season emission reductions under CAIR. It does not include information for the 3 States that are required to make annual emission reductions only.

season requirements would not change for States required to make ozone season reductions for CAIR.

Based on EPA modeling with Delaware and New Jersey included in the $PM_{2.5}$ region (and if all affected States choose to control EGUs), the EGU emissions caps and the ozone season NO_X emissions and emission reductions associated with those caps, for the 25 States and the District of Columbia that are required to make ozone season NO_X reductions, would be as shown in Table IV–15, above.[86]

TABLE IV–16.—SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSIONS CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (25 STATES AND DC) FOR THE INITIAL PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR ELECTRIC GENERATION UNITS IF EPA FINALIZES ITS PROPOSAL TO INCLUDE DELAWARE AND NEW JERSEY FOR $PM_{2.5}$ REQUIREMENTS

[Million tons] [87]

	First phase (2010 for SO_2 and 2009 for NO_X)			
	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
SO_2	8.8	3.7	5.2	3.6
NO_X	2.8	1.5	1.5	1.2
Sum	11.5	NA	6.7	4.8
	Second phase (2015 for SO_2 and NO_X)			
	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
SO_2	7.9	2.6	4.1	3.9
NO_X	2.8	1.3	1.3	1.5
Sum	10.7	NA	5.3	5.4

Note: Numbers may not add due to rounding.

1 The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–16. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.

2 The District of Columbia and the following 25 States would be affected by CAIR for annual SO_2 and NO_X controls if EPA finalizes its proposal to include DE and NJ: AL, DE, FL, GA, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI.

3 The 2010 SO_2 emissions cap would apply to years 2010 through 2014. The 2009 NO_X emissions cap would apply to years 2009 through 2014. The 2015 caps would apply to 2015 and beyond.

4 Due to the use of the existing bank of SO_2 allowances, the estimated SO_2 emissions in the CAIR region in 2010 and 2015 would be higher than the emissions caps.

5 Over time the banked SO_2 emissions allowances would be consumed and the 2015 cap level would be reached. SO_2 emissions levels can be thought of as on a flexible ''glide path'' to meet the 2015 CAIR cap with increasing reductions over time. The annual SO_2 emissions levels in 2020 with CAIR, within the region of States required to make annual reductions (including Delaware and New Jersey), are forecasted to be 3.3 million tons, an annual reduction of 4.4 million tons from base case levels.

The EPA apportioned the EGU caps—and associated required regionwide emission reductions—on a State-by-State basis. The affected States may determine the necessary controls on SO_2 and NO_X emissions to achieve the required reductions. The EPA's apportionment method and the resulting State EGU emissions budgets are described in Section V in today's preamble.

To achieve the required SO_2 and NO_X reductions in the most cost-effective manner, EPA suggests that States implement these reductions by controlling EGUs under a cap and trade program that EPA would implement.

However, the States have flexibility in choosing the sources that must reduce emissions. If the States choose to require EGUs to reduce their emissions, then States must impose a cap on EGU emissions, which would in effect be an annual emissions budget. Provisions for allocating SO_2 and NO_X allowances to individual EGUs—which apply if a State chooses to control EGUs and elects to allow them to participate in the interstate cap and trade program—are presented elsewhere in today's preamble. If a State wants to control EGUs, but does not want to allow EGUs to participate in the interstate cap and trade program, the State has flexibility in allocating allowances, but it must cap EGUs. Sources that are subject to the emission reduction requirements under title IV continue to be subject to those requirements.

If the States choose to control other sources, then they must employ methods to assure that those other sources implement controls that will yield the appropriate amount of annual emissions reduction. See section VII (SIP Criteria and Emissions Reporting Requirements) in today's preamble.

Implementation of the cap and trade program is discussed in section VIII in today's preamble.

For convenience, we use specific terminology to refer to certain concepts. ''State budget'' refers to the statewide

86 For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

87 Table IV–16 includes regionwide information for the 25 States and DC that will be required to make annual emission reductions if EPA finalizes its proposal to require annual reductions in Delaware and New Jersey under CAIR. The table does not include information for the 3 States (Arkansas, Connecticut, and Massachusetts) that would be affected by CAIR for ozone season reductions only.

emissions that may be used as an accounting technique to determine the amount of annual or ozone season emissions reductions that controls may yield. It does not imply that there is a legally enforceable statewide cap on emissions from all SO_2 or NO_X sources. ''Regionwide budget'' refers to the amount of emissions, computed on a regionwide basis, which may be used to determine State-by-State requirements. It does not imply that there is a legally enforceable regionwide cap on emissions from all SO_2 or NO_X sources. ''State EGU budget'' refers to the legally enforceable annual or ozone season emissions cap on EGUs a State would apply should it decide to control EGUs.

V. Determination of State Emissions Budgets

The EPA outlined in the NPR and SNPR its proposals regarding a methodology for setting both regional and State-level SO_2 and NO_X budgets. Section IV explains how the regionwide budgets were developed. This section V describes how EPA apportions the regionwide emissions reductions—and the associated EGU caps—on a State-by-State basis, so that the affected States may determine the necessary controls of SO_2 and NO_X emissions.

In the NPR and SNPR, EPA proposed annual SO_2 and NO_X caps for States contributing to fine particle nonattainment and separate ozone-season only caps for States contributing to ozone—but not fine particle—nonattainment. The EPA is finalizing an annual cap for both SO_2 and NO_X for States that contribute to fine particle nonattainment. In addition, EPA is finalizing an ozone-season only cap for NO_X for all States that contribute to ozone nonattainment.

States have several options for reducing emissions that significantly contribute to downwind nonattainment. They can adopt EPA's approach of reducing the emissions in a cost-effective manner through an interstate cap and trade program. This approach would, by definition, achieve the required cost-effective reductions. Alternately, States could achieve all of the necessary emissions reductions from EGUs, but choose not to use EPA's interstate emissions trading program. In this case, a State would need to demonstrate that it is meeting the EGU budgets outlined in this section. Finally, States could obtain at least some of their required emissions reductions from sources other than EGUs. Additional detail on these options is provided in section VII.

A. What Is the Approach for Setting State-by-State Annual Emissions Reductions Requirements and EGU Budgets?

This section presents the final methodologies used for apportioning regionwide emission reduction requirements or budgets to the individual States.

In the CAIR NPR, EPA proposed methods for determining the SO_2 and NO_X emission reduction requirements or budgets for each affected State. In the June 2004 SNPR, EPA proposed corrections and improvements to the proposals in the CAIR NPR. In the August 2004 NODA, EPA presented the corrected NO_X budgets resulting from the improvements proposed in the SNPR.

1. SO_2 Emissions Budgets

a. State Annual SO_2 Emission Budget Methodology

As noted elsewhere in today's preamble, the regionwide annual budget for 2015 and beyond is based on a 65 percent reduction of title IV allowances allocated to units in the CAIR States for SO_2 control. The regionwide annual SO_2 budget for the years 2010–2014 is based on a 50 percent reduction from title IV allocations for all units in affected States.

In the NPR and SNPR, EPA also proposed calculating annual State SO_2 budgets based on each State's allowances under title IV of the 1990 CAA Amendments. We are finalizing this proposed approach for determining State annual SO_2 budgets.

State annual budgets for the years 2010–2014 (Phase I) are based on a 50 percent reduction from title IV allocations for all units in the affected State. The State annual budget for 2015 and beyond (Phase II) is based on a 65 percent reduction of title IV allowances allocated to units in the affected State for SO_2 control.

Some commenters criticized EPA's basing State budgets on title IV allocations since these were based largely on 1985–1987 historic heat input data. Commenters argue that the initial allocation was not equitable and that in any event, the electric power sector has changed significantly. They conclude that State budgets should reflect those differences. Commenters have also commented that tying SO_2 allocations to title IV also does not let States account for units that are exempt from title IV or for new units that have come online since 1990.

While acknowledging these concerns, EPA believes, for a number of reasons, that setting State budgets according to title IV allowances represents a reasonable approach.

The EPA believes that basing budgets on title IV allowances is necessary in order to ensure the preservation of a viable title IV program, which is important for reasons discussed in section IX of this preamble. Such reasons include the desire to maintain the trust and confidence that has developed in the functioning market for title IV allowances. The EPA believes it is important not to undermine such confidence (which is an essential underpinning to a viable market-based system) recognizing that it is a key to the success of a trading program under the CAIR.

The title IV program represents a logical starting point for assessing emissions reductions for SO_2, since it is the current effective cap on SO_2 emissions for Acid Rain units, which make up the large majority of affected EGU CAIR units. It is from this starting emissions cap, that further CAIR reductions are required. Consequently, EPA proposes State-level reductions based on reductions from the initial allocations of title IV allowances to individual units at sources (power plants) in States covered by the CAIR.

The setting of SO_2 budgets differs from the setting of NO_X budgets for the CAIR, in part, because of this difference in starting points—since there is no existing NO_X regional annual cap, and no currency for emissions, on which sources rely. Furthermore, Congress, as part of title IV of the CAA, decided upon the allocations of title IV allowances specifically for the control of SO_2, and not for NO_X.

Moreover, Congress decided to allocate title IV allowances in perpetuity, realizing that the electricity sector would not remain static over this time period. Congress clearly did not choose a policy to regularly revisit and revise these allocations, believing that its allocations methodology for title IV allowances would be appropriate for future time periods.

The EPA realizes, putting aside concerns of linkage to title IV, that there are numerous potential methodologies of dividing up the regional budgets among the States. Also, EPA believes, that while initial allocations of State budgets are important for distributional reasons, under a cap and trade system, they would not impact the attainment of the environmental objectives or the overall cost of this rule.

Each of the alternate methods also has certain shortcomings, many of which have been identified by commenters. Basing allowances on historic emissions, for instance, would penalize

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States that have already gone through significant efforts to clean up their sources. Basing allowances on heat input has advantages, but cannot accommodate States that have worked to improve their energy efficiency. Basing allowances on output would provide gas-fired units with many more allowances than they need, rather than giving them to the coal-fired units that will be incurring the greatest costs from the tighter caps.

The EPA did look at a number of allowance outcomes using alternate potential methods for allocating SO_2 allowances. These methods included allocating on the basis of historic emissions, heat input (with alternatives based on heat input from all fossil generation, and heat input from coal- and oil-fired generation only) and output (with alternatives based on all generation and all fossil-fired generation). Allocating allowances based on title IV yields results that fall within a reasonable range of results obtained from using these alternate methodologies. In fact, calculating State budgets using title IV allowances yields budgets generally at or within the ranges of budgets calculated using the other methods in more than two-thirds of the States, which account for over 85 percent of the total heat input in the region from 1999–2002. This analysis is discussed further in the response to comments document.

b. Final SO_2 State Emission Budget Methodology

The EPA is finalizing the budgets as noted in the SNPR, adjusting for the proper inclusion of States covered under the final CAIR. The final State budgets are included in Table V–1 below. Details of the data and methodology used to calculate these budgets are included in the accompanying ''Regional and State SO_2 and NO_X Emissions Budgets'' Technical Support Document.

TABLE V–1.—FINAL ANNUAL ELECTRIC GENERATING UNITS SO_2 BUDGETS

[Tons]

State	State SO_2 budget 2010*	State SO_2 budget 2015**
Alabama	157,582	110,307
District of Columbia	708	495
Florida	253,450	177,415
Georgia	213,057	149,140
Illinois	192,671	134,869
Indiana	254,599	178,219
Iowa	64,095	44,866
Kentucky	188,773	132,141
Louisiana	59,948	41,963
Maryland	70,697	49,488
Michigan	178,605	125,024
Minnesota	49,987	34,991
Mississippi	33,763	23,634
Missouri	137,214	96,050
New York	135,139	94,597
North Carolina	137,342	96,139
Ohio	333,520	233,464
Pennsylvania	275,990	193,193
South Carolina	57,271	40,089
Tennessee	137,216	96,051
Texas	320,946	224,662
Virginia	63,478	44,435
West Virginia	215,881	151,117
Wisconsin	87,264	61,085
Total	3,619,196	2,533,434

*Annual budget for SO_2 tons covered by allowances for 2010–2014.

**Annual budget for SO_2 tons covered by allowances for 2015 and thereafter.

c. Use of SO_2 Budgets

These specific levels of the proposed State budgets would actually provide binding statewide caps on EGU emissions for States that choose to control only EGUs but do not want to participate in the trading program. For States choosing to participate in the trading program, these State budgets would not be binding, instead, the States' SO_2 reductions would be achieved solely through the application of required retirement ratios as discussed in section VII of this preamble. For States controlling both EGUs and non-EGUs (or controlling only non-EGUs), these State budgets would be used to calculate the emissions reductions requirements for non-EGUs and the remaining reduction requirement for EGUs. This is described in more detail in the section VII discussion on SIP approvability.

2. NO_X Annual Emissions Budgets

a. Overview

In this section, EPA discusses the apportioning of regionwide NO_X annual emission reduction requirements or budgets to the individual States. In the January 2004 proposal, we proposed State EGU annual NO_X budgets based on each State's average share of recent historic heat input. In the SNPR, we proposed the same input-based methodology, but revised the budgets based on more complete heat input data. Also, EPA took comment on an alternative methodology that determines State budgets by multiplying heat input data by adjustment factors for different fuels. In the August NODA, EPA presented the corrected annual NO_X budgets resulting from the improved methodology proposed in the SNPR.

b. State Annual NO_X Emissions Budget Methodology

Proposed and Discussed NO_X Emission Budget Methodology

As noted elsewhere in today's preamble, EPA determined historical annual heat input data for Acid Rain Program units in the applicable States and multiplied by 0.15 lb/mmBtu (for 2009) and 0.125 lb/mmBtu (for 2015) to determine total annual NO_X regionwide budgets for the CAIR region. The EPA applied these rates to each individual State's total highest annual heat input for any year from 1999 through 2002. Thus, EPA used the heat input total for the year in which a State's total heat input was the highest.

In the January 2004 proposal, we proposed annual NO_X State budgets for a 28-State (and D.C.) region based on each jurisdiction's average heat input—using heat input data from Acid Rain Program units—over the years 1999 through 2002. We summed the average heat input from each of the applicable jurisdictions to obtain a regional total average annual heat input. Then, each State received a pro rata share of the regional NO_X emissions budget based on the ratio of its average annual heat input to the regional total average annual heat input.

In the SNPR, EPA proposed to revise its determination of State NO_X budgets by supplementing Acid Rain Program unit data with annual heat input data from the U.S. Energy Information Administration (EIA), for the non-Acid Rain unit data. A number of commenters had suggested that this would better reflect the heat input of the units that will be controlled under the CAIR, and EPA agrees.

In the SNPR, EPA asked for, and subsequently received, comments on determining State budgets by multiplying heat input data by adjustment factors for different fuels. The factors would reflect the inherently higher emissions rate of coal-fired units, and consequently the greater burden on coal units to control emissions.

Today's Rule

As noted earlier in the case of SO_2, EPA recognizes that the choice of method in setting State budgets, with a given regionwide total annual budget, makes little difference in terms of the levels of resulting regionwide annual

SO_2 and NO_X emissions reductions. If States choose to control EGUs and participate in the cap and trade program, allowances could be freely traded, encouraging least-cost compliance over the entire region. In such a case, the least-cost outcome would not depend on the relative levels of individual State budgets.

A number of commenters have stated, without supporting analysis or evidence, that budgets based on heat input, (and particularly those that would use different fuel factors) do not encourage efficiency. Economic theory indicates that neither a heat input, nor an output-based approach, if allocated once and based on a historical baseline, would provide any incentives for more or less efficient generation (changes in future behavior would have no impact on allocations). The cap and trade system itself, regardless of how the allowances are distributed, provides the primary incentive for more efficient, cleaner generation of electricity.

The EPA is finalizing an approach of calculating State budgets through a fuel-adjusted heat-input basis. State budgets would be determined by multiplying historic heat input data (summed by fuel) by different adjustment factors for the different fuels. These factors reflect for each fuel (coal, gas and oil), the 1999–2002 average emissions by State, summed for the CAIR region, divided by average heat input by fuel by State, summed for the CAIR region. The resulting adjustment factors from this calculation are 1.0 for coal, 0.4 for gas and 0.6 for oil. The factors would reflect the inherently higher emissions rate of coal-fired plants, and consequently the greater burden on coal plants to control emissions.

Such an approach provides States with allowances more in proportion with their historical emissions. It provides for a more equitable budget distribution by recognizing that different States are facing the reduction requirements with different starting stocks of generation, with different starting emission profiles.[88] The fuel burned is a key factor in differentiating the generation.

However, this approach is not equivalent to an approach based strictly on historical emissions (which would give fewer allowances to States which have already cleaned up their coal plants). Under the approach we are finalizing today, heat input from all coal, whether clean or uncontrolled, would be counted equally in determining State budgets. Likewise, all heat input from gas, whether clean or uncontrolled, from a steam-gas unit or from a combined-cycle plant, would be counted equally in determining State budgets.

It is not expected that this decision would disadvantage States with significant gas-fired generation. One reason is that the calculation of the adjusted heat input for natural gas generation generally includes significant historic heat input and emissions from older, less efficient and dirtier steam gas units. These units' capacity factors are declining and are expected to decline further over time as new, cleaner and more efficient combined-cycle gas units increase their generation.

It is important to note that the methodology by which the NO_X State budgets are determined need not be used by individual States in determining allocations to specific sources. As discussed in section VIII of this document (Model Trading Rule), EPA is offering States the flexibility to allocate allowances from their budgets as they see fit.

Finally, EPA discussed in the January 2004 proposal, a methodology used in the NO_X SIP Call (67 FR 21868) that applied State-specific growth rates for heat input in setting State budgets.[89] The EPA, in the SNPR, noted that it is not proposing to use this method for the CAIR because we believe that other methods are reasonable, and that methods involving State-specific growth rates present certain challenges due to the inherent difficulties in predicting State-specific growth in heat input over a lengthy period, especially for jurisdictions that are only a part of a larger regional electric power dispatch region. Several commenters stated their support for incorporating growth, believing that not taking growth into account would penalize States with higher growth. However, a significant number of commenters stated their opposition to using growth in setting State budgets, noting the problems that arose in the NO_X SIP Call. The EPA believes that setting budgets using a heat input approach, without a growth adjustment, is fair, would be simpler and would involve less risk of resulting litigation.

c. Final Annual State NO_X Emission Budgets

The final annual State NO_X emission budgets following this method are included in Table V–2 below. Details of the numbers and methodology used to calculate these budgets are included in the ''Regional and State SO_2 and NO_X Emissions Budgets'' Technical Support Document.

TABLE V–2.—FINAL ANNUAL ELECTRIC GENERATING UNITS NO_X BUDGETS

[Tons]

State	State NO_X budget 2009*	State NO_X budget 2015**
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966
Total	1,504,871	1,254,061

*Annual budget for NO_X tons covered by allowances for 2009–2014.

**Annual budget for NO_X tons covered by allowances for 2015 and thereafter.

d. Use of Annual NO_X Budgets

These proposed State budgets would serve as effective binding caps on State emissions, if States chose to control only EGUs, but did not want to participate in the trading program. For States controlling both EGUs and non-EGUs (or controlling only non-EGUs), these budgets would be compared to a baseline level of emissions to calculate the emissions reductions requirements for non-EGUs and the required caps for EGUs. This process is described in more detail in the section VII discussion on SIP approvability.

e. NO_X Compliance Supplement Pool

As is discussed in section I, EPA is establishing a NO_X compliance supplement pool of 198,494 tons, which would result in a total compliance supplement pool of approximately 200,000 tons of NO_X when combined with EPA's proposed rulemaking to include Delaware and New Jersey. The

[88] States receiving larger budgets under this approach are generally expected to be those having to make the most reductions.

[89] With a methodology similar to that used in the NO_X SIP Call, annual State NO_X budgets would be set by using a base heat input data, then adjusting it by a calculated growth rate for each jurisdiction's annual EGU heat inputs.

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EPA is apportioning the compliance supplement pool to States based on the assumption that a State's need for allowances from the pool is proportional to the magnitude of the State's required emissions reductions (as calculated using the State's base case emissions and annual NO_X budget). The EPA is apportioning the 200,000 tons of NO_X on a pro-rata basis, based on each State's share of the total emissions reductions requirement for the region in 2009. This is consistent with the methodology used in the NO_X SIP Call. Table V–3 presents each State's compliance supplement pool.

TABLE V–3.—STATE NO_X COMPLIANCE SUPPLEMENT POOLS

[Tons]

State	Base case 2009 emissions	2009 State annual NO_X budget	Reduction requirement	Compliance supplement pool *
Alabama	132,019	69,020	62,999	10,166
District of Columbia	0	144	0	0
Florida	151,094	99,445	51,649	8,335
Georgia	143,140	66,321	76,819	12,397
Illinois	146,248	76,230	70,018	11,299
Indiana	233,833	108,935	124,898	20,155
Iowa	75,934	32,692	43,242	6,978
Kentucky	175,754	83,205	92,549	14,935
Louisiana	49,460	35,512	13,948	2,251
Maryland	56,662	27,724	28,938	4,670
Michigan	117,031	65,304	51,727	8,347
Minnesota	71,896	31,443	40,453	6,528
Mississippi	36,807	17,807	19,000	3,066
Missouri	115,916	59,871	56,045	9,044
New York	45,145	45,617	0	0
North Carolina	59,751	62,183	0	0
Ohio	263,814	108,667	155,147	25,037
Pennsylvania	198,255	99,049	99,206	16,009
South Carolina	48,776	32,662	16,114	2,600
Tennessee	106,398	50,973	55,425	8,944
Texas	185,798	181,014	4,784	772
Virginia	67,890	36,074	31,816	5,134
West Virginia	179,125	74,220	104,905	16,929
Wisconsin	71,112	40,759	30,353	4,898
CAIR region subtotal				198,494
Delaware	9,389	4,166	5,223	843
New Jersey	16,760	12,670	4,090	660
Total				199,997

* Rounding to the nearest whole allowance results in a total compliance supplement pool of 199,997 tons.

B. What Is the Approach for Setting State-by-State Emissions Reductions Requirements and EGU Budgets for States With NO_X Ozone Season Reduction Requirements?

1. States Subject to Ozone-Season Requirements

In the NPR, EPA proposed that Connecticut contributes significantly to ozone nonattainment in another State, but not to fine particle nonattainment. As a result of subsequent air quality modeling, EPA has also found that Massachusetts, New Jersey, Delaware and Arkansas contribute significantly to ozone nonattainment in another State, but not to fine particle nonattainment. In this final rule, EPA is establishing a regionwide ozone-season budget for all States that contribute significantly to ozone nonattainment in another State, regardless of their contribution to fine particle nonattainment. The following 25 States, plus the District of Columbia, are found to contribute significantly to ozone nonattainment: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

These States are subject to an ozone season NO_X cap, which covers the 5 months of May through September. The EPA is calculating the ozone season cap level for the 25 States plus the District of Columbia region by multiplying the region's ozone season heat input by 0.15 lb/mmBtu for 2009 and 0.125 lb/mmBtu for 2015. Heat input for the region was estimated by looking at reported ozone season Acid Rain heat inputs for each State for the years 1999 through 2002, and selecting the single year highest heat input for each State as a whole.

As is the case for the annual NO_X State Budgets, EPA is finalizing an approach of calculating ozone season NO_X State budgets through a fuel-adjusted heat input basis. State budgets would be determined by multiplying State-level average historic ozone-season heat input data (summed by fuel) by different adjustment factors for the different fuels (1.0 for coal, 0.4 for gas, and 0.6 for oil). The total ozone season State budgets are then determined by calculating each State's share of total fuel-adjusted heat input, and multiplying this share by the regionwide budget.

The budgets for these States in 2009 and 2015 are included in Table V–4 below.

TABLE V–4.—FINAL SEASONAL ELECTRICITY GENERATING UNIT NO_X BUDGETS

[Tons]

State	State NO_X budget 2009 *	State NO_X budget 2015 **
Alabama	32,182	26,818
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989
Total	567,744	484,506

* Seasonal budget for NO_X tons covered by allowances for 2009–2014. For States that have lower EGU budgets under the NO_X SIP Call than their 2009 CAIR budget, table V–4 includes their SIP Call budget. For Connecticut, the NO_X SIP Call budget is also used for 2015 and beyond.

** Seasonal budget for NO_X tons covered by allowances for 2015 and thereafter.

VI. Air Quality Modeling Approach and Results

Overview

In this section we summarize the air quality modeling approach used for the proposed rule, we address major comments on the fundamental aspects of EPA's proposed approach, and we describe the updated and improved approach, based on those comments, that we are finalizing today. This section also contains the results of EPA's final air quality modeling, including: (1) Identifying the future baseline $PM_{2.5}$ and 8-hour ozone nonattainment counties in the East; (2) quantifying the contribution from emissions in upwind States to nonattainment in these counties; (3) quantifying the air quality impacts of the CAIR reductions on $PM_{2.5}$ and 8-hour ozone; and (4) describing the impacts on visibility in Class I areas of implementing CAIR compared to implementing the regional haze requirement for best available retrofit technology (BART).

We present the air quality models, model configuration, and evaluation; and then the emissions inventories and meteorological data used as inputs to the air quality models. Next, we provide the updated interstate contributions for $PM_{2.5}$ and 8-hour ozone and those States that make a significant contribution to downwind nonattainment, before considering cost. Finally, we present the estimated impacts of the CAIR emissions reductions on air quality and visibility. As described below, our air quality modeling for today's rule utilizes the Community Multiscale Air Quality (CMAQ) model in conjunction with 2001 meteorological data for simulating $PM_{2.5}$ concentrations and associated visibility effects and the Comprehensive Air Quality Model with Extensions (CAMx) with meteorological data for three episodes in 1995 for simulating 8-hour ozone concentrations. Our approach to modeling both $PM_{2.5}$ and 8-hour ozone involves applying these tools (*i.e.*, CMAQ for $PM_{2.5}$ and CAMx for 8-hour ozone) using updated emissions inventory data for 2001, 2010, and 2015 to project future baseline concentrations, interstate transport, and the impacts of CAIR on projected nonattainment of $PM_{2.5}$ and 8-hour ozone. We provide additional information on the development of our updated CAIR air quality modeling platform, the modeling analysis techniques, model evaluation, and results for $PM_{2.5}$ and 8-hour ozone modeling in the CAIR Notice of Final Rulemaking Emissions Inventory Technical Support Document (NFR EITSD) and the Air Quality Modeling Technical Support Document (NFR AQMTSD).

A. What Air Quality Modeling Platform Did EPA Use?

1. Air Quality Models

a. The $PM_{2.5}$ Air Quality Model and Evaluation

Overview

In the NPR, we used the Regional Model for Simulating Aerosols and Deposition (REMSAD) as the tool for simulating base year and future concentrations of $PM_{2.5}$. Like most photochemical grid models, the predictions of REMSAD are based on a set of atmospheric specie mass continuity equations. This set of equations represents a mass balance in which all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes are expressed in mathematical terms. The modeling domain used for this analysis covers the entire continental United States and adjacent portions of Canada and Mexico.

The EPA applied REMSAD for an annual simulation using meteorology and emissions for 1996. We used the results of this 1996 Base Year model run to evaluate how well the modeling system (*i.e.*, the air quality model and input data sets) replicated measured data over the time period and domain simulated. We performed a model evaluation for $PM_{2.5}$ and speciated components (*e.g.*, sulfate, nitrate, elemental carbon, organic carbon, etc.) as well as nitrate, sulfate and ammonium wet deposition, and visibility. The evaluation used available 1996 ambient measurements paired with REMSAD predictions corresponding to the location and time periods of the measured data. We quantified model performance using various statistical and graphical techniques. Additional information on the model evaluation procedures and results are included in the Notice of Proposed Rulemaking Air Quality Modeling Technical Support Document (NPR AQMTSD).

The EPA received numerous comments on various elements of the proposed $PM_{2.5}$ air quality modeling approach. The major comments are responded to below. Other comments are addressed the Response to Comment (RTC) document. Regarding REMSAD, commenters argued that: (1) The REMSAD model is an inappropriate tool for modeling $PM_{2.5}$; (2) the scientific formulation of the model is simplistic and outdated and that other models with better science are available and should be used; and (3) results from REMSAD are directionally correct but better tools should be used as the basis for the final determinations on transport and projected nonattainment.

We agree that models with more refined science are available for $PM_{2.5}$ modeling and we have selected one of these models, the CMAQ as the tool for $PM_{2.5}$ modeling for the final CAIR. The CMAQ model is a publicly available, peer-reviewed, state-of-the-science model with a number of science attributes that are critical for accurately simulating the oxidant precursors and non-linear organic and inorganic chemical relationships associated with the formation of sulfate, nitrate, and organic aerosols. Several of the important science aspects of CMAQ that are superior to REMSAD include: (1) Updated gaseous/heterogeneous chemistry that provides the basis for the formation of nitrates and includes a

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current inorganic nitrate partitioning module; (2) in-cloud sulfate chemistry, which accounts for the non-linear sensitivity of sulfate formation to varying pH; (3) a state-of-the-science secondary organic aerosol module that includes a more comprehensive gas-particle partitioning algorithm from both anthropogenic and biogenic secondary organic aerosol; and (4) the full CB–IV chemistry mechanism, which provides a complete simulation of aerosol precursor oxidants.

However, even though REMSAD does not have all the scientific refinements of CMAQ, we believe that REMSAD treats the key physical and chemical processes associated with secondary aerosol formation and transport. Thus, we believe that the conclusions based on the proposal modeling using REMSAD are valid and therefore support today's findings based only on CMAQ that: (1) There will be widespread $PM_{2.5}$ nonattainment in the eastern U.S. in 2010 and 2015 absent the reductions from CAIR; (2) upwind States in the eastern part of the United States contribute to the $PM_{2.5}$ nonattainment problems in other downwind States; (3) States with high emissions tend to contribute more than States with low emissions; (4) States close to nonattainment areas tend to contribute more than other States farther upwind; and (5) the CAIR controls will produce major benefits in terms of bringing areas into or closer to attainment.

Comments and Responses

(i) REMSAD Science and Evaluation

Comment: Some commenters stated that REMSAD is an inappropriate model for use in simulating $PM_{2.5}$. Other commenters said, more specifically, that the chemical mechanism in REMSAD (*i.e.*, micro CB–IV) is simplified and not validated, and that the model has not been scientifically peer-reviewed.

Response: The EPA disagrees with comments claiming that REMSAD is an inappropriate tool for modeling $PM_{2.5}$. The EPA believes that REMSAD is appropriate for regional and national modeling applications because the model does include the key physical and chemical processes associated with secondary aerosol formation and transport.[90]

Specifically, REMSAD simulates both gas phase and aerosol chemistry. The gas phase chemistry uses a reduced-form version of Carbon Bond chemical mechanism (micro-CB–IV). Formation of inorganic secondary particulate species, such as sulfate and nitrate, are simulated through chemical reactions within the model. Aerosol sulfate is formed in both the gas phase and the aqueous phase. The REMSAD model also accounts for the production of secondary organic aerosols through chemistry processes involving volatile organic compounds (VOC) and directly emitted organic particles. Emissions of non-reactive particles (*e.g.*, elemental carbon) are treated as inert species which are advected and deposited during the simulation.

With regard to comments on the micro CB–IV chemical mechanism, although this mechanism treats fewer organic carbon species compared to the full CB–IV, the inorganic portion of the reduced mechanism is identical to the full chemical mechanism. The intent of the CB–IV mechanism is to: (a) Provide a faithful representation of the linkages between emissions of ozone precursor species and secondary aerosol precursor species; (b) treat the oxidizing capacity of the troposphere, represented primarily by the concentrations of radicals and hydrogen peroxide; and (c) simulate the rate of oxidation of the nitrogen oxide (NO_X) and sulfur dioxide (SO_2), which are precursors to secondary aerosols. The EPA agrees that micro CB–IV is simplified compared to the full CB–IV mechanism. However, performance testing of micro CB–IV indicates that this simplified mechanism is similar to the full CB–IV chemical mechanism in simulating ozone formation and approximates other species reasonably well (*e.g.*, hydroxyl radical, hydroperoxy radical, the operator radical, hydrogen peroxide, nitric acid, and peroxyacetyl nitrate).[91]

The REMSAD model was subjected to a scientific peer-review (Seigneur *et al.*, 1999) and EPA has incorporated the major science improvements that were recommended by the peer-review panel. These improvements were included in the version of REMSAD used for the NPR modeling. Specifically, the following updates have been implemented into REMSAD Version 7.06, which was used for the proposed CAIR control strategy simulations: (1) The nighttime chemistry treatment was updated to improve the treatment of the gas phase species NO_3 and N_2O_5; (2) the effects of temperature and pressure dependence on chemical rates were added; (3) the MARS–A aerosol partitioning module was added for calculating particle and gas phase fractions of nitrate; (4) aqueous phase formation of sulfate was updated by including reactions for oxidation of SO_2 by ozone and oxygen, (5) peroxynitric acid (PNA) chemistry was added; and (6) a module for calculating biogenic and anthropogenic secondary organic aerosols was developed and integrated into REMSAD. We believe that these changes adequately respond to the peer review comments and have bolstered the scientific credibility of this model.

(ii) Use of CMAQ Instead of REMSAD for $PM_{2.5}$ Modeling

Comment: Some commenters claimed that REMSAD is outdated and that other models with more sophisticated science are available. Commenters said that EPA should utilize the best available science through use of the most comprehensive photochemical model for simulating aerosols. Commenters specifically stated that EPA should use more recently developed models such as the CMAQ model or the aerosol version of the Comprehensive Air Quality Model with Extensions (CAM_X–PM).

Response: The EPA agrees that photochemical models are now available that are more scientifically sophisticated than REMSAD. In this regard, and in response to commenters' recommendations on specific models, EPA has selected CMAQ as the modeling tool for the final CAIR modeling analysis. As stated above, the CMAQ model is a publicaly available, peer-reviewed, state-of-the-science model with a number of science attributes that are critical for accurately simulating the oxidant precursors and non-linear organic and inorganic chemical relationships associated with the formation of sulfate, nitrate, and organic aerosols. As listed above, the important science aspects of CMAQ that are superior to REMSAD include: (1) Updated gaseous/heterogeneous chemistry that provides the basis for the formation of nitrates and includes a current inorganic nitrate partitioning module; (2) in-cloud sulfate chemistry, which accounts for the non-linear sensitivity of sulfate formation to varying pH; (3) a state-of-the-science secondary organic aerosol module that includes a more comprehensive gas-particle partitioning algorithm from both anthropogenic and biogenic secondary organic aerosol; and (4) the full CB–IV chemistry mechanism, which provides a complete simulation of aerosol precursor oxidants.

(iii) Model Evaluation

Comment: A number of commenters claimed that EPA's air quality model evaluation for 1996 was deficient because it lacked sufficient ambient measurements, especially in urban

[90] Even so, EPA acknowledges that REMSAD has certain limitations not found in CMAQ.

[91] Whitten, G. memorandum: Comparison of REMSAD Reduced Chemistry to Full CB–4. February 19, 2001.

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areas, to judge model performance. Commenters said that EPA should: (1) Update the evaluation to a more recent time period in order to take advantage of greatly expanded ambient $PM_{2.5}$ species measurements, especially in urban areas; and (2) calculate model performance statistics over monthly and/or seasonal time periods using daily/weekly observed/model-predicted data pairs.

Some commenters said that the 1996 data were so limited that it is not possible to determine whether REMSAD could be used with confidence to assess the effects of emissions changes. Still, other commenters said that the performance of REMSAD for the 1996 modeling platform was poor.

Commenters acknowledged that there are no universally accepted or EPA-recommended quantitative criteria for judging the acceptability of $PM_{2.5}$ model performance. In the absence of such model performance acceptance criteria, some commenters said that performance should be judged by comparing EPA's model performance results to the range of results obtained by other groups in the air quality modeling community who conducted other recent regional $PM_{2.5}$ model applications. A few commenters also identified specific model performance ranges and criteria that they said should be achievable for sulfate and $PM_{2.5}$, given the current state-of-science for aerosol modeling and measurement uncertainty. The specific values cited by these commenters are ±30 percent to ±50 percent for fractional bias, 50 percent to 75 percent for fractional error, and 50 percent for normalized error.

Response: The EPA agrees that the limited amount of ambient $PM_{2.5}$ species data available in 1996 affected our ability to evaluate model performance, especially in urban areas, and there were deficiencies in the performance of REMSAD using the 1996 model inputs. Also, EPA agrees that a model evaluation should be performed for a more recent time period in order to address these concerns. Thus, we conclude that the 1996 modeling platform which includes 1996 emissions, 1996 meteorology, and 1996 ambient data should be updated and improved, as recommended by commenters.

The EPA has developed a new modeling platform which includes emissions, meteorological data, and other model inputs for 2001. This platform was used to confirm the ability of our modeling system to replicate ambient $PM_{2.5}$ and component species in both urban and rural areas and, thus, establish the credibility of this platform for $PM_{2.5}$ modeling as part of CAIR.[92] In 2001, there was an extensive set of ambient $PM_{2.5}$ measurements including 133 urban Speciation Trends Network (STN) monitoring sites across the nation, with 105 of these in the East. This network did not exist in 1996. Also, the number of mainly suburban and rural monitoring sites in the Clean Air Status and Trends Network (CASTNET) and Interagency Monitoring of Protected Visual Environments (IMPROVE) network has increased to over 200 in 2001, compared to approximately 120 operating in 1996.

The EPA evaluated CMAQ for the 2001 modeling platform using the extensive set of 2001 monitoring data for $PM_{2.5}$ species. The evaluation included a statistical analysis in which the model predictions and measurements were paired in space and in time (*i.e.*, daily or weekly to be consistent with the sampling protocol of the monitoring network). Model performance statistics were calculated for each network with separate statistics for sites in the West and the East.[93] In response to comments that performance statistics should be calculated over monthly and/or seasonal time periods, we elected to use seasonal time periods in order to be consistent with our use of quarterly average $PM_{2.5}$ species as part of the procedure for projecting future concentrations, as described below in section VI.B.1. In addition, the sampling frequency at the CASTNET, IMPROVE, and STN sites may not provide sufficient samples in a 1-month period to provide a robust calculation of model performance statistics. Details of EPA's model evaluation for CMAQ using the 2001 modeling platform are in the report ''Updated CMAQ Model Performance Evaluation for 2001'' which can be found in the docket for today's rule.

The EPA agrees that there are no universally accepted performance criteria for $PM_{2.5}$ modeling and that performance should be judged by comparison to the performance found by other groups in the air quality modeling community. In this respect, we have compared our CMAQ 2001 model performance results to the range of performance found in other recent regional $PM_{2.5}$ model applications by other groups.[94] Details of this comparison can be found in the CMAQ evaluation report. Below is a summary of performance results from other, non-EPA modeling studies, for summer sulfate and winter nitrate. It CAIR. Overall, the general range of fractional bias (FB) and fractional error (FE) statistics for the better performing model applications are as follows:

—Summer sulfate is in the range of ¥10 percent to +30 percent for FB and 35 percent to 50 percent for FE; and

—Winter nitrate is in the range of +50 percent to +70 percent for FB and 85 percent to 105 percent for FE.

The corresponding performance statistics for EPA's 2001 CMAQ application as well as the 1996 REMSAD application used for the proposal modeling are provided in Table VI–1.

TABLE VI–1.—SELECTED PERFORMANCE EVALUATION STATISTICS FROM THE CMAQ 2001 SIMULATION AND THE REMSAD 1996 SIMULATION

Eastern U.S.	CMAQ 2001		REMSAD 1996	
	FB(%)	FE(%)	FB(%)	FE(%)
Sulfate (Summer):				
STN	14	44	....	....
Improve	10	42	¥20	51
CASTNet	3	22	¥21	59
Nitrate (Winter)				
STN	15	73	....	....

[92] The 2001 modeling platform is described in full in the NFR EITSD and NFR AQMTSD.

[93] For the purposes of this analysis, we have defined ''East'' as the area to the east of 100 degrees longitude, which runs from approximately the eastern half of Texas through the eastern half of North Dakota.

[94] These other modeling studies represent a wide range of modeling analyses which cover various models, model configurations, domains, years and/or episodes, chemical mechanisms, and aerosol modules.

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TABLE VI–1.—SELECTED PERFORMANCE EVALUATION STATISTICS FROM THE CMAQ 2001 SIMULATION AND THE REMSAD 1996 SIMULATION—Continued

Eastern U.S.	CMAQ 2001		REMSAD 1996	
	FB(%)	FE(%)	FB(%)	FE(%)
Improve	21	92	67	103

The results indicate that the performance for CMAQ in 2001 is within the range or better than that found by other groups in recent applications. The performance also meets the benchmark goals suggested by several commenters. In addition, the CMAQ performance is considerably improved over that of the REMSAD 1996 performance for summer sulfate and winter nitrate, which were near the bounds or outside the range of other recent applications.

The CMAQ model performance results give us confidence that our applications of CMAQ using the new modeling platform provide a scientifically credible approach for assessing $PM_{2.5}$ concentrations for the purposes of CAIR.

b. Ozone Air Quality Modeling Platform and Model Evaluation

Overview

The EPA used the CAM_X, version 3.10 in the NPR to assess 8-hour ozone concentrations and the impacts of ozone and ozone precursor transport on elevated levels of ozone across the eastern U.S. The CAM_X is a publicly available Eulerian model that accounts for the processes that are involved in the production, transport, and destruction of ozone over a specified three-dimensional domain and time period. The CAM_X model was run with 1995/96 base year emissions to evaluate the performance of the modeling platform to replicate observed concentrations during the three 1995 episodes. This evaluation was comprised principally of statistical assessments of hourly, 1-hour daily maximum, and 8-hour daily maximum ozone predictions. As described in the NPR AQMTSD, model performance of CAM_X for ozone was judged against the results from previous regional ozone model applications. This analysis indicates that model performance was comparable to or better than that found in previous applications and is, therefore, acceptable for the purposes of CAIR ozone modeling.

The EPA did not receive comments on the CAM_X model or the model performance for ozone. The EPA did receive comments on the choice of episodes for ozone modeling, the meteorological data for these episodes, the spatial resolution of our modeling, and consistency between ozone and $PM_{2.5}$ modeling in terms of methods for projecting future air quality concentrations. As described below and in the RTC document and NFR AQMTSD, we continue to believe that: (1) The three 1995 episodes are representative episodes for regional modeling of 8-hour ozone; and (2) the meteorological data for these episodes and spatial resolution are adequate for use in our modeling for CAIR. Thus, the ozone air quality assessments in today's rule rely on CAM_X modeling of meteorological data for the three 1995 episodes for the domain and spatial resolution used for the NPR. As discussed below, we ran CAM_X for the updated 2001 emissions inventory and the updated 2010 and 2015 base case inventories as part of the process to project 8-hour ozone for these future year scenarios. We revised our method of projecting future ozone concentrations to be consistent with the method we are using for $PM_{2.5}$.

c. Model Grid Cell Configuration

As described in the NPR AQMTSD, the $PM_{2.5}$ modeling for the proposal was performed for a domain (*i.e.*, area) covering the 48 States and adjacent portions of Canada and Mexico. Within this domain, the model predictions were calculated for a grid network with a spatial resolution of approximately 36 km. Our 8-hour ozone modeling for proposal was performed using a nested grid network. The outer portion of this grid has a spatial resolution of approximately 36 km. The inner ''nested'' area, which covers a large portion of the eastern U.S., has a resolution of approximately 12 km.

Comment: Some commenters said that the 36 km grid cell size used by EPA in modeling $PM_{2.5}$ and the 36 km/12 km grid resolution used for ozone modeling are too coarse and are inconsistent with EPA's draft modeling guidance.

Response: We disagree with these comments and continue to believe that the grid dimensions for our $PM_{2.5}$ modeling and our 8-hour ozone modeling are not too coarse nor are they inconsistent with our draft guidance documents for $PM_{2.5}$ modeling [95] and ozone modeling.[96] The draft guidance for $PM_{2.5}$ modeling states that 36 km resolution is acceptable for regional scale applications in portions of the domain outside of nonattainment areas. For portions of the domain which cover nonattainment areas, 12 km resolution or less is recommended by the guidance. However, as stated in the guidance document, these recommendations were based on guidance for 8-hour ozone modeling because there was a lack of $PM_{2.5}$ modeling at different grid resolutions at the time the guidance was drafted. In addition, the $PM_{2.5}$ guidance states that exceptions to these recommendations can be made on a case-by-case basis.

For several reasons, we believe that 36 km resolution is sufficient for $PM_{2.5}$ modeling for the purposes of CAIR. First, recent analyses that compare 36 km to 12 km modeling of $PM_{2.5}$ [97] indicate that spatial mean concentrations of gas phase and aerosol species at 36 km and 12 km are quite similar. A comparison of model predictions versus observations indicates that the model performance is similar at 12 km and 36 km in both rural and urban areas. Thus, using 12 km resolution does not necessarily provide any additional confidence in the results. Second, ambient measurements of sulfate and to a significant extent nitrate, which are the pollutants of most importance for CAIR, do not exhibit large spatial differences between rural and urban areas, as described elsewhere in today's rule. This implies that it is not necessary to use fine resolution modeling in order to properly capture

[95] U.S. EPA, 2000: Draft Guidance for Demonstrating Attainment of the Air Quality Goals for $PM_{2.5}$ and Regional Haze; Draft 1.1, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[96] U.S. EPA, 1999: Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[97] VISTAS Emissions and Air Quality Modeling—Phase I Task 4cd Report: Model Performance Evaluation and Model Sensitivity Tests for Three Phase I Episodes. ENVIRON International Corporation, Alpine Geophysics, and University of California at Riverside, September 7, 2004.

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the regional concentration patterns of these pollutants.

Our draft 8-hour ozone modeling guidance recommends using 36 km resolution for regional modeling with nested grid cells not exceeding 12 km over urban portions of the modeling domain. The guidance states that 4 to 5 km resolution for urban areas is preferred, if feasible. In addition, if 12 km modeling is used then plume-in-grid treatment for large point sources of NO_X should be considered.

Our modeling for CAIR is consistent with this guidance in that we use 36 km resolution for the outer portions of the region; 12 km resolution covering nearly all urban areas in the domain; and a plume-in-grid algorithm for major NO_X point sources in the region. In addition, analyses that compare model 12 km resolution to 4 km resolution for portions of our 1995 episodes indicate that the spatial fields predicted at both 12 km and 4 km have many common features in terms of the areas of high and low ozone.[98] In a comparison of model predictions to observation, the 12 km modeling was found to be somewhat more accurate than the finer 4 km modeling.

2. Emissions Inventory Data

For the proposed rule, emissions inventories were created for the 48 contiguous States and the District of Columbia. These inventories were estimated for a 2001 base year to reflect current emissions and for 2010 and 2015 future baseline scenarios. The inventories were prepared for electric generating units (EGUs), industrial and commercial sources (non-EGUs), stationary area sources, on-road vehicles, and non-road engines. The inventories contained both annual and typical summer season day emissions for the following pollutants: oxides of nitrogen (NO_X); volatile organic compounds (VOC); carbon monoxide (CO); sulfur dioxide (SO_2); direct particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) and less than 2.5 micrometers ($PM_{2.5}$); and ammonia (NH_3). A summary of the development of these inventories is provided below. Additional information on the emissions inventory used for proposal can be found in the NPR AQMTSD.

Because the complete 2001 National Emission Inventory (NEI) and future-year projections consistent with that NEI were not available in a form suitable for air quality modeling when needed for the proposal, we developed a reasonably representative ''proxy'' inventory for 2001. For the EGU, mobile, and non-road emissions sectors, 1996-to-2001 adjustment ratios were created by dividing State-level total emissions for each pollutant for 2001 by the corresponding consistent 1996 emissions. These adjustment ratios were then multiplied by the REMSAD-ready 1996 emissions for these two sectors to produce REMSAD-ready files for the 2001 proxy. For non-EGUs and stationary area sources, linear interpolations were performed between the REMSAD-ready 1996 emissions and the REMSAD-ready 2010 base case emissions to produce 2001 proxy emissions for these two sectors. Details on the creation of the 2001 proxy inventory used for proposal are provided in the NPR AQMTSD.

The NPR future 2010 and 2015 base case emissions reflect projected economic growth and control programs that are to be implemented by 2010 and 2015, respectively. Control programs included in these future base cases include those State, local, and Federal measures already promulgated and other significant measures expected to be promulgated before the final rule is implemented. Future year 2010 and 2015 base case EGU emissions were obtained from versions 2.1 and 2.1.6 of the Integrated Planning Model (IPM).

Comment: Several commenters stated that the emission inventory used for the ''proxy'' 2001 base year was not sufficient for the rulemaking, primarily because it was developed from a 1996 modeling inventory by applying various adjustment factors. Commenters suggested that: (1) More up-to-date inventories were now available and should be used; (2) the most recent Continuous Emissions Monitoring (CEM) data or throughput information should be used to derive a 2001 EGU inventory; and (3) EPA should use the 2001 MOBILE6 and NONROAD2002 models for estimating on-road mobile and non-road engine emissions, respectively.

Response: The EPA believes that the base year for modeling should be as recent as possible, given the availability of nationally complete emissions estimates and ambient monitoring data. For the analyses of the final rule, EPA has used a base year inventory developed specifically for 2001. The base year inventory for the electric utility sector now uses measured CEM emissions data for 2001. The non-EGU point source and stationary-area source sectors are based on the final 1999 NEI data submittals from State, local, and Tribal air agencies. This inventory is the latest available quality-assured and reviewed national emission data set for these sectors. The 1999 data for non-EGU point and stationary-area sources were projected to represent a 2001 inventory using State/county-specific and sector-specific growth rates. The on-road mobile inventory uses MOBILE version 6.2 and the non-road engines inventory uses the NONROAD2004 model, both with updated input parameters to calculate emissions for 2001. More detailed information on the development of the emissions inventories can be found in the NFR EITSD.

Comment: Commenters stated that EPA failed to develop an accurate and comprehensive ammonia emission inventory from soil, fertilizer, and animal husbandry sources.

Response: The 2001 inventory used for the analyses for the final rule includes a new national county-level ammonia inventory developed by EPA using the latest emission rates selected based on a comprehensive literature review, and activity levels as provided by the U.S. Census of Agriculture for animal husbandry. The 2001 inventory from fertilizer application sources was compiled from State and local submissions to EPA for 1999, augmented as necessary with EPA estimates, and grown to 2001 using State/county-specific and category-specific growth rates. With regard to background soil emissions of NH_3, EPA believes that the current state of understanding of background soil ammonia releases and sinks is insufficient to warrant including these emission sources in modeling inventories at this time.

Comment: Two commenters indicated that EPA should revise 2010 and 2015 base case emissions by improving the methods for estimating economic growth and not rely on the Bureau of Economic Analysis (BEA) data used for proposal.

Response: In response to these comments, EPA has refined its economic growth projections. In addition to updated versions of the MOBILE6, NONROAD, and IPM models, EPA developed new economic growth rates for stationary, area, and non-EGU point sources. For these two sectors, the final approach uses a combination of: (1) Regional or national fuel-use forecast data from the U.S. Department of Energy for source types that map to fuel use sectors (*e.g.,* commercial coal, industrial natural gas); (2) State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, version 5.5; and (3) forecasts by

[98] Irwin, J. et al. ''Examination of model predictions at different horizontal grid resolutions.'' Submitted for Publication to Environmental Fluid Mechanics.

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specific industry organizations and Federal agencies. For more detail on the growth methodologies, please refer to the NFR EITSD.

3. Meteorological Data

In order to solve for the change in pollutant concentrations over time and space, the air quality model requires certain meteorological inputs that, in part, govern the formation, transport, and destruction of pollutant material. Two separate sets of meteorological inputs were used in the air quality modeling completed as part of the NPR. The meteorological input files for the proposal $PM_{2.5}$ modeling were developed from a Fifth-Generation NCAR/Pennsylvania State Mesoscale Model (MM5) model simulation for the entire year of 1996. The gridded meteorological data for the three 1995 ozone episodes were developed using the Regional Atmospheric Modeling System (RAMS). Both of these models are publicly-available, widely-used, prognostic meteorological models that solve the full set of physical and thermodynamic equations which govern atmospheric motions. Further, each of these specific meteorological data sets has been utilized in past EPA rulemaking modeling analyses (*e.g.,* the Nonroad Land-based Diesel Engines Standards).

Comment: Several commenters claimed that the 1996 meteorological modeling data used to support the fine particulate modeling were outdated and non-representative. We also received recommendations from commenters on benchmarks to be used as goals for judging the adequacy of meteorological modeling.

Response: The EPA draft $PM_{2.5}$ modeling guidance which provides general recommendations on meteorological periods to model for $PM_{2.5}$ purposes lists three primary general criteria for consideration: (a) Variety of meteorological conditions; (b) existence of an extensive air quality/ meteorological data bases; and (c) sufficient number of days. The approach recommended in the guidance for modeling annual $PM_{2.5}$ is to use a single, representative year. Based on the comments received and the criteria outlined in the guidance, EPA developed meteorological data for the entire calendar year of 2001. This year was chosen for the $PM_{2.5}$ modeling platform based on several factors, specifically: (a) It corresponds to the most recent set of emissions data; (b) there are considerable ambient $PM_{2.5}$ species data for use in model evaluation (as described in section VI.A.1., above); and (c) Federal Reference Method (FRM) $PM_{2.5}$ data for this year are included in the calculation of the most recent $PM_{2.5}$ design values used for designating $PM_{2.5}$ nonattainment areas. In view of these factors, EPA believes that 2001 meteorology are representative for $PM_{2.5}$ modeling for the purposes of this rule.

The new 2001 meteorological data used for $PM_{2.5}$ modeling were derived from an updated version of the MM5 model used for the 1996 meteorology used for proposal. The version of MM5 used for the 2001 simulation contains more sophisticated physics options with respect to features like cloud microphysics and land-surface interactions, and more refined vertical resolution of the atmosphere compared to the version used for modeling 1996 meteorology. While there are currently no universally accepted criteria for judging the adequacy of meteorological model performance, EPA compared the 2001 MM5 model performance against the benchmark goals [99] recommended by some commenters. The benchmark goals suggest that temperature bias should be within the range of approximately $\pm$ 0.5 degrees C and errors less than or equal to 2.0 degrees C are typical.

In general, the model performance statistics for our 2001 meteorological modeling are in line with the above benchmark goals. Specfically, the mean temperature bias of our 2001 meteorological modeling was approximately 0.6 degrees C and the mean error was approximately 2.0 degrees C. The evaluation of the 2001 MM5 for humidity (water vapor mixing ratio) shows biases of less than 0.5 g/kg and errors of approximately 1 g/kg, which compare favorably to the goals of $\pm$ 1 g/kg for bias and 2 g/kg or less error. Model performance for winds in our 2001 simulation was also improved compared to what has historically been found in MM5 modeling studies. The index of agreement for surface winds in the 2001 case equaled 0.86, which is far better than the benchmark goal of 0.60. The precipitation evaluation results show that the model generally replicates the observed data, but is overestimating precipitation in the summer months. More information about the model performance evaluation and the MM5 configuration is provided in the NFR AQMTSD.

Comment: Several groups criticized the lack of quantitative meteorological model evaluation data for the 1995 RAMS meteorological modeling used for episodic ozone modeling.

Response: A peer-reviewed, quantitative evaluation of the RAMS model performance for this meteorological period is provided by Hogrefe, *et al.*[100] This analysis was performed using RAMS predictions for June through August of 1995. The results show that the RAMS biases and errors are generally in line with past meteorological model simulations by other groups outside EPA. The EPA remains satisfied that the 1995 RAMS meteorological inputs for the three CAM_X ozone modeling episodes are of sufficient quality and we have continued to use these inputs for the ozone analyses for the final rule.

Comment: The EPA received several comments on the episodes selected for ozone modeling. There was general criticism that the ozone modeling did not follow EPA's own guidance for the selection of episodes. Additionally, there was specific criticism that the episodes did not provide for a reasonable test of the 8-hour ozone NAAQS in some areas.

Response: The draft 8-hour ozone guidance recommends, at a minimum, that four criteria be used to select episodes which are appropriate to model. This guidance is generally intended for local attainment demonstrations, as opposed to regional transport analyses, but it does recommend that in applying a regional model one should choose episodes meeting as many of the criteria as possible, though it acknowledges there may be tradeoffs. Given the large number of nonattainment areas within the ozone domain, it would be extremely difficult to assess the criteria on a area-by-area basis. However, from a general perspective, the 1995 episodes address all of the primary criteria, which include: (1) A variety of meteorological conditions; (2) measured ozone values that are close to current air quality; (3) extensive meteorological and air quality data; and (4) a sufficient number of days. More detail is provided in the NFR AQMTSD, but here is a brief description of how each of the four primary criteria are met by the 1995 cases.

With regard to the criteria of meteorological variations, we have completed inert tracer simulations for each of the three 1995 episodes that show different transport patterns in all three cases. For example the June case involves east-to-west transport; the July case involves west-to-east transport; and

[99] Environ, Enhanced Meteorological Modeling and Performance Evaluation for Two Texas Ozone Episodes. August 2001.

[100] Hogrefe, C. *et al.* "Evaluating the performance of regional-scale photochemical modeling systems: Part 1-meteorological predictions." Atmospherics Environment, vol. 35 (2001), pp. 4159–4174.

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the August case involves south-to-north transport. In a separate analysis to determine whether the 1995 modeling days correspond to commonly occurring and ozone-conducive meteorology, EPA has applied a multi-variate statistical approach for characterizing daily meteorological patterns and investigating their relationship to 8-hour ozone concentrations in the eastern U.S. Across the 16 sites for which the analysis was completed, there were five to six distinct sets of meteorological conditions, called regimes, that occurred during the ozone seasons studied. An analysis of the 8-hour daily maximum ozone concentrations for each of the meteorological regimes was undertaken to determine the distribution of ozone concentrations and the frequency of occurrence of each regimes. The EPA determined that between 60 and 70 percent of the episode days we modeled are associated with the most frequently occurring, high ozone potential, meteorological regimes. These results also provide support that the episodes being modeled are representative of conditions present when high ozone concentrations are measured throughout the modeling domain. For the second criteria, EPA has completed an analysis which shows that the 1995 episodes contain observed 8-hour daily maximum ozone values that approximate recent ambient concentrations over the eastern U.S. Additional analyses performed by EPA and others have concluded that each of the three episodes involves widespread areas of elevated ozone concentrations. The synoptic meteorological pattern of the July 1995 episode has been identified by one of the commenters as representing a classic set of conditions necessary for high ozone over the eastern U.S. While the ozone was not quite as widespread in the June and August 1995 episodes, these periods also contained exceedances of the 8-hour ozone NAAQS in most portions of the region.

We believe that there is ample meteorological and air quality data available to support an evaluation of the modeling for these episodes. Specifically, there were over 700 ozone monitors reporting across the domain for use in model evaluation. As noted above, the model performance for these episodes compares favorably to the recommendations in EPA's urban modeling guidance. In addition, the modeling period is comprised of 30 days, not including model ramp-up periods which is considerably more than is typically used in an attainment demonstration modeling submitted to EPA by a State. Finally, EPA's draft ozone guidance also indicates as one of four secondary criteria that extra weight can be assigned to modeling episodes for which there is prior experience in modeling. The 1995 CAIR ozone episodes have been successfully used to drive the air quality modeling completed for several recent notice-and-comment rulemakings (Tier-2, Heavy Duty Engine, and NonRoad). Based on the analyses discussed above and the adherence to the modeling guidance, EPA is satisfied that the 1995 CAMx episodes are appropriate for continued use.

B. How Did EPA Project Future Nonattainment for $PM_{2.5}$ and 8-Hour Ozone?

1. Projection of Future $PM_{2.5}$ Nonattainment

a. Methodology for Projecting Future $PM_{2.5}$ Nonattainment

In the NPR, we assessed the prospects for future attainment and nonattainment in 2010 and 2015 of the $PM_{2.5}$ annual NAAQS. The approach for identifying areas expected to be nonattainment for $PM_{2.5}$ in the future involved using the model predictions in a relative way to forecast current $PM_{2.5}$ design values to 2010 and 2015. The modeling portion of this approach included annual simulations for 2001 proxy emissions and for 2010 and 2015 base case emissions scenarios. As described below, the predictions from these runs were used to calculate relative reduction factors (RRFs) which were then applied to current $PM_{2.5}$ design values from FRM sites in the East. This approach is consistent with the procedures in the draft of EPA's $PM_{2.5}$ modeling guidance.

To determine the current $PM_{2.5}$ air quality for use in projecting design values to the future, we selected the higher of the 1999–2001 or 2000–2002 design value (the most recent ambient data at the time of the proposal) for each monitor that measured nonattainment in 2000–2002. For those sites that were attaining the $PM_{2.5}$ standard based on their 2000–2002 design value, we used the value from this period as the starting point for projecting 2010 and 2015 air quality at these sites.

The procedure for calculating future year $PM_{2.5}$ design values is called the Speciated Modeled Attainment Test (SMAT). The test uses model predictions in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. These species are sulfate, nitrate, organic carbon, elemental carbon, crustal, and un-attributed mass. The relative change in model-predicted species concentrations were applied to ambient species measurements in order to project each species for the future year scenarios. We applied a spatial interpolation to the IMPROVE and STN speciation data as a means for estimating species composition fractions for the FRM monitoring sites. Future year $PM_{2.5}$ was calculated by summing the projected concentrations of each species. The SMAT technical procedures, as applied for the NPR, are contained in the NPR and NPR AQMTSD.

As noted above, the procedures for determining future year $PM_{2.5}$ concentrations were applied for each FRM site. For counties with only one FRM site, the forecast design value for that site was used to determine whether or not the county was predicted to be nonattainment in the future. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year concentrations of 15.1 $\mu g/m^3$ (as rounded up from 15.05 $\mu g/m^3$) or more were predicted to be nonattainment. Based on the modeling performed for the NPR, 61 counties in the East were forecast to be nonattainment for the 2010 base case. Of these, 41 were forecast to remain nonattainment for the 2015 base case.

Comment: Some commenters said that EPA has not established the credibility of using models in a relative sense to estimate future $PM_{2.5}$ concentrations and that poor performance of REMSAD for 1996 calls into question the use of models to adequately determine the effects of changes in emissions. One commenter said that a mechanistic model evaluation, in which model predictions of $PM_{2.5}$ precursor photochemical oxidants are compared to corresponding measurements, is an approach for gaining confidence in the ability of a model to provide a credible response to emission changes.

Response: The EPA believes the future year nonattainment projections should be based on using model predictions in a relative sense. By applying the model in a relative way, each measured component of $PM_{2.5}$ is adjusted upward or downward based on the percent change in that component, as determined by the ratio of future year to base year model predictions. The EPA feels that by using this approach, we are able to reduce the risk that overprediction or underprediction of $PM_{2.5}$ component species may unduly affect our projection of future year nonattainment.

The EPA agrees with commenters that one way to establish confidence in the credibility of this approach is to

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determine whether model predictions of $PM_{2.5}$ precursors are generally comparable to corresponding measured data. In this regard, we compared the CMAQ predictions to observations for several precursor gases for which measurements were available in 2001. These gases include sulfur dioxide, nitric acid, and ozone.

The results for the East are summarized in Table VI–2. Additional details on this analysis can be found in the CMAQ evaluation report. The results indicate that for both summer and winter ozone, the fractional bias and error is within the recommended range for urban scale ozone modeling included in EPA's draft guidance for 8-hour ozone modeling. For the other species examined, there are limited ambient data and few other studies against which to compare our findings. Still, our performance results for these species are within the range suggested as acceptable by commenters for sulfate (*i.e.*, ±30 percent to ±60 percent for fractional bias and 50 percent to 75 percent for fractional error). Thus, CMAQ is considered appropriate and credible for use in projecting changes in future year $PM_{2.5}$ concentrations and the resultant health/economic benefits due to the emissions reductions.

TABLE VI–2.—CMAQ MODEL PERFORMANCE STATISTICS FOR OZONE, TOTAL NITRATE, AND NITRIC ACID IN THE EAST

Eastern U.S.	CMAQ 2001	
	FB (%)	FE (%)
Ozone:		
AIRS (Summer)	13	21
AIRS (Winter)	¥9	31
Sulfur Dioxide:		
CASTNet (Summer)	31	48
CASTNet (Winter)	39	43
Nitric Acid:		
CASTNet (Summer)	29	39
CASTNet (Winter)	¥21	55

Comment: Several commenters said that EPA's SMAT approach is flawed and suggested alternative methods for attributing individual species mass to the FRM measured $PM_{2.5}$ mass. One commenter detailed several different methods to apportion the FRM mass to individual $PM_{2.5}$ species. They refer to two different estimation methods as the ''FRM equivalent'' approach and the ''best estimate'' approach.

Response: The EPA agrees that alternative methodologies can be used to apportion $PM_{2.5}$ species fractions to the FRM data. We believe that revising SMAT to use a methodology similar to an ''FRM equivalent'' methodology, as described in the Notice of Data Availability (69 FR 47828; August 6, 2004), is warranted. Since nonattainment designation determinations and future year nonattainment projections are based on measured FRM data, we believe that the $PM_{2.5}$ species data should be adjusted to best conform to what is measured on the FRM filters. Based on comments, EPA has revised our technique for projecting current $PM_{2.5}$ data to incorporate some aspects of the commenter's ''FRM equivalent'' methodology. As described in more detail in the NFR AQMTSD, we believe our revised methodology to be the most technically appropriate way of estimating what is measured on the FRM filters.

Full documentation of the revised EPA SMAT methodology is contained in the updated SMAT report [101]. In brief, we revised the SMAT methodology to take into account several known differences between what is measured by speciation monitors and what is measured on FRM filters. Among the revisions were calculations to account for nitrate, ammonium, and organic carbon volatilization, blank $PM_{2.5}$ mass, particle bound water, the degree of neutralization of sulfate, and the uncertainty in estimating organic carbon mass.

Comment: Several commenters noted that the future year design values were based on projections of the 1999–2001 and/or 2000–2002 FRM monitoring data and that there are more recent design value data available for the 2001–2003 design value period. Commenters also noted that the 2001–2003 data shows lower $PM_{2.5}$ concentrations at the majority of sites and therefore, by projecting the highest design value, we are overestimating the future year $PM_{2.5}$ values.

Response: As stated above, the $PM_{2.5}$ projection methodology in the NPR used the higher of the 1999–2001 or 2000–2002 $PM_{2.5}$ design value data. The draft modeling guidance for $PM_{2.5}$ specifies the use of the higher of the three design value periods which straddle the emissions year. The emissions year is 2001 and therefore the three periods would be 1999–2001, 2000–2002, and 2001–2003. Since the 2001–2003 data is now available, we are using it as part of the current year $PM_{2.5}$ calculations for the final rule.

The observation by a commenter that the 2001–2003 data are generally lower than in the previous two design value periods (*i.e.*, 1999–2001 and 2000–2002) leads to the issue of how to reduce the influence of year-to-year variability in meteorology and emissions on our estimate of current air quality. As a consequence of this year-to-year variability in concentrations, relying on design values from any single period, as in the approach used for proposal, may not provide a robust representation of current air quality for use in forecasting the future. Specifically, the lower $PM_{2.5}$ values in 2001–2003 may not be representative of the current modeling period. To address the issue of year-to-year variability in the ambient data we have modified our methodology to use an average of the three design value periods that straddle the base year emissions year (*i.e.*, 2001). In this case it is the average of the 1999–2001, 2000–2002, and 2001–2003 design values. The average of the three design values is not a straight 5-year average. Rather, it is a weighted average of the 1999–2003 period. That is, by averaging 1999–2001, 2000–2002, and 2001–2003, the value from 2001 is weighted three times; 2000 and 2002 are each weighted twice and 1999 and 2003 are each weighted once. This approach has the desired benefits of: (1) weighting the $PM_{2.5}$ values towards the middle year of the 5-year period, which is the 2001 base year for

[101] Procedures for Estimating Future $PM_{2.5}$ Values for the CAIR Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT), docket number OAR–2003–0053–1907.

our emissions projections; and (2) smoothing out the effects of year-to-year variability in emissions and meteorology that occurs over the full 5-year period. We have adopted this method for use in projecting future $PM_{2.5}$ nonattainment for the final rule analysis. We plan to incorporate this new methodology into the next draft version of our $PM_{2.5}$ modeling guidance.

b. Projected 2010 and 2015 Base Case $PM_{2.5}$ Nonattainment Counties

For the final rule, we have revised the projected $PM_{2.5}$ nonattainment counties for 2010 and 2015 by applying CMAQ for the entire year (*i.e.*, January through December) of 2001 using 2001 Base Year and 2010 and 2015 future base case emissions from the new modeling platform, as described in section VI.A.2. The 2010 and 2015 base case $PM_{2.5}$ nonattainment counties were determined applying the updated SMAT method using current 1999–2003 $PM_{2.5}$ air quality coupled with the $PM_{2.5}$ species from the 2001 Base Year and 2010 and 2015 base case CMAQ model runs. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year design values of 15.05 μg/m^3 or higher were predicted to be nonattainment. The result is that, without controls beyond those included in the base case, 79 counties in the East are projected to be nonattainment for the 2010 base case. For the 2015 base case, 74 counties in the East are projected to be nonattainment for $PM_{2.5}$.

In light of the uncertainties inherent in regionwide modeling many years into the future, of the 79 nonattainment counties projected for the 2010 base case, we have the most confidence in our projection of nonattainment for those counties that are not only forecast to be nonattainment in 2010, based on the SMAT method, but that also measure nonattainment for the most recent period of available ambient data (*i.e.*, 2001–2003). In our analysis for the 2010 base case, there are 62 such counties in the East that are both ‘‘modeled’’ nonattainment and currently have ‘‘monitored’’ nonattainment. We refer to these counties as having ‘‘modeled plus monitored’’ nonattainment. Out of an abundance of caution, we are using only these 62 ‘‘modeled plus monitored’’ counties as the downwind receptors in determining which upwind States make a significant contribution to $PM_{2.5}$ in downwind States.

The 79 counties in the East that we project will be nonattainment for $PM_{2.5}$ in 2010 and the subset of 62 counties that are also ‘‘monitored’’ nonattainment in 2001–2003, are identified in Table VI–3. The 2015 base case $PM_{2.5}$ nonattainment counties are provided in Table VI–4.

TABLE VI–3.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M^3) FOR NONATTAINMENT COUNTIES IN THE 2010 BASE CASE

State	County	2010 Base	‘‘Modeled + Monitored’’
Alabama	DeKalb Co	15.23	No.
Alabama	Jefferson Co	18.57	Yes.
Alabama	Montgomery Co	15.12	No.
Alabama	Morgan Co	15.29	No.
Alabama	Russell Co	16.17	Yes.
Alabama	Talladega Co	15.34	No.
Delaware	New Castle Co	16.56	Yes.
District of Columbia		15.84	Yes.
Georgia	Bibb Co	16.27	Yes.
Georgia	Clarke Co	16.39	Yes.
Georgia	Clayton Co	17.39	Yes.
Georgia	Cobb Co	16.57	Yes.
Georgia	DeKalb Co	16.75	Yes.
Georgia	Floyd Co	16.87	Yes.
Georgia	Fulton Co	18.02	Yes.
Georgia	Hall Co	15.60	No.
Georgia	Muscogee Co	15.65	No.
Georgia	Richmond Co	15.68	No.
Georgia	Walker Co	15.43	Yes.
Georgia	Washington Co	15.31	No.
Georgia	Wilkinson Co	16.27	No.
Illinois	Cook Co	17.52	Yes.
Illinois	Madison Co	16.66	Yes.
Illinois	St. Clair Co	16.24	Yes.
Indiana	Clark Co	16.51	Yes.
Indiana	Dubois Co	15.73	Yes.
Indiana	Lake Co	17.26	Yes.
Indiana	Marion Co	16.83	Yes.
Indiana	Vanderburgh Co	15.54	Yes.
Kentucky	Boyd Co	15.23	No.
Kentucky	Bullitt Co	15.10	No.
Kentucky	Fayette Co	15.95	Yes.
Kentucky	Jefferson Co	16.71	Yes.
Kentucky	Kenton Co	15.30	No.
Maryland	Anne Arundel Co	15.26	Yes.
Maryland	Baltimore City	16.96	Yes.
Michigan	Wayne Co	19.41	Yes.
Missouri	St. Louis City	15.10	No.
New Jersey	Union Co	15.05	Yes.
New York	New York Co	16.19	Yes.
North Carolina	Catawba Co	15.48	Yes.
North Carolina	Davidson Co	15.76	Yes.
North Carolina	Mecklenburg Co	15.22	No.
Ohio	Butler Co	16.45	Yes.

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TABLE VI–3.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu G/M^3$) FOR NONATTAINMENT COUNTIES IN THE 2010 BASE CASE—Continued

State	County	2010 Base	"Modeled + Monitored"
Ohio	Cuyahoga Co	18.84	Yes.
Ohio	Franklin Co	16.98	Yes.
Ohio	Hamilton Co	18.23	Yes.
Ohio	Jefferson Co	17.94	Yes.
Ohio	Lawrence Co	16.10	Yes.
Ohio	Mahoning Co	15.39	Yes.
Ohio	Montgomery Co	15.41	Yes.
Ohio	Scioto Co	18.13	Yes.
Ohio	Stark Co	17.14	Yes.
Ohio	Summit Co	16.47	Yes.
Ohio	Trumbull Co	15.28	No.
Pennsylvania	Allegheny Co	20.55	Yes.
Pennsylvania	Beaver Co	15.78	Yes.
Pennsylvania	Berks Co	15.89	Yes.
Pennsylvania	Cambria Co	15.14	Yes.
Pennsylvania	Dauphin Co	15.17	Yes.
Pennsylvania	Delaware Co	15.61	Yes.
Pennsylvania	Lancaster Co	16.55	Yes.
Pennsylvania	Philadelphia Co	16.65	Yes.
Pennsylvania	Washington Co	15.23	Yes.
Pennsylvania	Westmoreland Co	15.16	Yes.
Pennsylvania	York Co	16.49	Yes.
Tennessee	Davidson Co	15.36	No.
Tennessee	Hamilton Co	16.89	Yes.
Tennessee	Knox Co	17.44	Yes.
Tennessee	Sullivan Co	15.32	No.
West Virginia	Berkeley Co	15.69	Yes.
West Virginia	Brooke Co	16.63	Yes.
West Virginia	Cabell Co	17.03	Yes.
West Virginia	Hancock Co	17.06	Yes.
West Virginia	Kanawha Co	17.56	Yes.
West Virginia	Marion Co	15.32	Yes.
West Virginia	Marshall Co	15.81	Yes.
West Virginia	Ohio Co	15.14	Yes.
West Virginia	Wood Co	16.66	Yes.

TABLE VI–4.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M<>^{3}) FOR NONATTAINMENT COUNTIES IN THE 2015 BASE CASE

State	County	2015 Base
Alabama	DeKalb Co	15.24
Alabama	Jefferson Co	18.85
Alabama	Montgomery Co	15.24
Alabama	Morgan Co	15.26
Alabama	Russell Co	16.10
Alabama	Talladega Co	15.22
Delaware	New Castle Co	16.47
District of Columbia		15.57
Georgia	Bibb Co	16.41
Georgia	Chatham Co	15.06
Georgia	Clarke Co	16.15
Georgia	Clayton Co	17.46
Georgia	Cobb Co	16.51
Georgia	DeKalb Co	16.82
Georgia	Floyd Co	17.33
Georgia	Fulton Co	18.00
Georgia	Hall Co	15.36
Georgia	Muscogee Co	15.58
Georgia	Richmond Co	15.76
Georgia	Walker Co	15.37
Georgia	Washington Co	15.34
Georgia	Wilkinson Co	16.54
Illinois	Cook Co	17.71
Illinois	Madison Co	16.90
Illinois	St. Clair Co	16.49
Illinois	Will Co	15.12
Indiana	Clark Co	16.37
Indiana	Dubois Co	15.66
Indiana	Lake Co	17.27
Indiana	Marion Co	16.77

TABLE VI–4.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M<>^{3}) FOR NONATTAINMENT COUNTIES IN THE 2015 BASE CASE—Continued

State	County	2015 Base
Indiana	Vanderburgh Co	15.56
Kentucky	Boyd Co	15.06
Kentucky	Fayette Co	15.62
Kentucky	Jefferson Co	16.61
Kentucky	Kenton Co	15.09
Maryland	Baltimore City	17.04
Maryland	Baltimore Co	15.08
Michigan	Wayne Co	19.28
Mississippi	Jones Co	15.18
Missouri	St. Louis City	15.34
New York	New York Co	15.76
North Carolina	Catawba Co	15.19
North Carolina	Davidson Co	15.34
Ohio	Butler Co	16.32
Ohio	Cuyahoga Co	18.60
Ohio	Franklin Co	16.64
Ohio	Hamilton Co	18.03
Ohio	Jefferson Co	17.83
Ohio	Lawrence Co	15.92
Ohio	Mahoning Co	15.13
Ohio	Montgomery Co	15.16
Ohio	Scioto Co	17.92
Ohio	Stark Co	16.86
Ohio	Summit Co	16.14
Ohio	Trumbull Co	15.05
Pennsylvania	Allegheny Co	20.33
Pennsylvania	Beaver Co	15.54
Pennsylvania	Berks Co	15.66
Pennsylvania	Delaware Co	15.52
Pennsylvania	Lancaster Co	16.28
Pennsylvania	Philadelphia Co	16.53
Pennsylvania	York Co	16.22
Tennessee	Davidson Co	15.36
Tennessee	Hamilton Co	16.82
Tennessee	Knox Co	17.34
Tennessee	Shelby Co	15.17
Tennessee	Sullivan Co	15.37
West Virginia	Berkeley Co	15.32
West Virginia	Brooke Co	16.51
West Virginia	Cabell Co	16.86
West Virginia	Hancock Co	16.97
West Virginia	Kanawha Co	17.17
West Virginia	Marshall Co	15.52
West Virginia	Wood Co	16.69

2. Projection of Future 8-Hour Ozone Nonattainment

a. Methodology for Projecting Future 8-Hour Ozone Nonattainment

The approach for projecting future 8-hour ozone concentrations used by EPA in the NPR was based on applying the model in a relative sense to estimate the change in ozone between the base year (2001) and each future scenario. Projected 8-hour ozone design values in 2010 and 2015 were estimated by combining the relative change in model predicted ozone from 2001 to the future scenario with an estimate of the base year ambient 8-hour ozone design value. These procedures for calculating future case ozone design values are consistent with EPA's draft modeling guidance for 8-hour ozone attainment demonstrations. The draft guidance specifies the use of the higher of the design values from (a) the period that straddles the emissions inventory base year or (b) the design value period which was used to designate the area under the ozone NAAQS. At the time of the proposal, 2000–2002 was the design value period which both straddled the 2001 base year inventory and was also the latest period available.

Comment: Commenters noted that the procedures used by EPA for projecting future 8-hour ozone concentrations differ from the procedures used for projecting $PM_{2.5}$. These commenters said that EPA should harmonize the two approaches.

Response: In response to comments, we have made several changes in the approach to projecting future 8-hour ozone nonattainment in order to follow an approach that is consistent with the manner in which $PM_{2.5}$ projections are determined. The approach we are using to project $PM_{2.5}$ for the final rule analysis is described in section VI.B.1, above. In order to harmonize the ozone approach with the approach used for $PM_{2.5}$, we are using the weighted average of the design values for the periods that straddle the emission base year (*i.e.*, 2001). These periods are 1999–2001, 2000–2002, and 2001–2003. In this approach, the fourth-high ozone value from 2001 is weighted three times, 2000 and 2002 are weighted twice, and 1999 and 2003 are weighted once. This has the desired effect of weighting the projected ozone values towards the middle year of the 5-year period, which is the emissions year (2001), while

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accounting for the emissions and meteorological variability that occurs over the full 5-year period. The average weighted concentration is expected to be more representative as a starting point for future year projections than choosing (a) the single design value period that straddles the base year or (b) the design value used for designations. We plan to incorporate this new methodology into the next draft version of our ozone modeling guidance.

Comment: One commenter claimed that the 2010 and 2015 ozone projections in the proposal base cases were too optimistic, that is, that the modeling was underestimating the number of areas that may be in nonattainment in the future. The commenter urged a more conservative approach to assessing the future attainment status of areas.

Response: The technical basis for the comment stemmed from the assertion that the regional ozone modeling that EPA performed for the proposal was not of ''SIP-quality.'' The EPA response to the specific technical issues with regard to episode selection and grid resolution can be found in section VI.A as well as in the response to comments document. The EPA remains confident that the CAIR 8-hour ozone modeling platform is appropriate for assessing potential levels of future nonattainment.

b. Projected 2010 and 2015 Base Case 8-Hour Ozone Nonattainment Counties

For the final rule, we have revised our projections of ozone nonattainment for the 2010 and 2015 base cases by applying CAMx for the three 1995 ozone episodes using 2001 Base Year and 2010 and 2015 future base case emissions from the new modeling platform, as described in section VI.A.2. The revised 2010 and 2015 base case 8-hour ozone nonattainment counties were determined by applying the relative change in 8-hour ozone predicted by these CAMx model runs to the weighted average 1999–2003 8-hour ozone concentrations as described above and, in more detail, in the NFR AQMTSD. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year design values of 85 parts per billion (ppb) or higher were predicted to be nonattainment.

As a result of our updated modeling we project that, without controls beyond those in the base case, there will be 40 8-hour ozone nonattainnment counties in 2010 and 22 nonattainment counties in 2015. All of the 40 counties that we are projecting to be nonattainment for the 2010 base case are also measuring nonattainment based on the most recent design value period (*i.e.*, 2001–2003). We refer to these counties as ''modeled plus monitored'' nonattainment, as described above in section IV.B.1 for $PM_{2.5}$. We are using these 40 counties as the downwind receptors to determine which States make a significant contribution to 8-hour ozone nonattainment in downwind States.

The counties we are projecting to be nonattainment for 8-hour ozone in the 2010 base case and 2015 base case are listed in Table VI–5 and Table VI–6, respectively.

TABLE VI–5.—PROJECTED 2010 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)

State	County	2010 Base
Connecticut	Fairfield Co	92.6
Connecticut	Middlesex Co	90.9
Connecticut	New Haven Co	91.6
Delaware	New Castle Co	85.0
District of Columbia		85.2
Georgia	Fulton Co	86.5
Maryland	Anne Arundel Co	88.8
Maryland	Cecil Co	89.7
Maryland	Harford Co	93.0
Maryland	Kent Co	86.2
Michigan	Macomb Co	85.5
New Jersey	Bergen Co	86.9
New Jersey	Camden Co	91.9
New Jersey	Gloucester Co	91.8
New Jersey	Hunterdon Co	89.0
New Jersey	Mercer Co	95.6
New Jersey	Middlesex Co	92.4
New Jersey	Monmouth Co	86.6
New Jersey	Morris Co	86.5
New Jersey	Ocean Co	100.5
New York	Erie Co	87.3
New York	Richmond Co	87.3
New York	Suffolk Co	91.1
New York	Westchester Co	85.3
Ohio	Geauga Co	87.1
Pennsylvania	Bucks Co	94.7
Pennsylvania	Chester Co	85.7
Pennsylvania	Montgomery Co	88.0
Pennsylvania	Philadelphia Co	90.3
Rhode Island	Kent Co	86.4
Texas	Denton Co	87.4
Texas	Galveston Co	85.1
Texas	Harris Co	97.9
Texas	Jefferson Co	85.6
Texas	Tarrant Co	87.8
Virginia	Arlington Co	86.2
Virginia	Fairfax Co	85.7
Wisconsin	Kenosha Co	91.3
Wisconsin	Ozaukee Co	86.2

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TABLE VI–5.—PROJECTED 2010 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)—Continued

State	County	2010 Base
Wisconsin	Sheboygan Co	88.3

TABLE VI–6.—PROJECTED 2015 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)

State	County	2015 Base
Connecticut	Fairfield Co	91.4
Connecticut	Middlesex Co	89.1
Connecticut	New Haven Co	89.8
Maryland	Anne Arundel Co	86.0
Maryland	Cecil Co	86.9
Maryland	Harford Co	90.6
Michigan	Macomb Co	85.1
New Jersey	Bergen Co	85.7
New Jersey	Camden Co	89.5
New Jersey	Gloucester Co	89.6
New Jersey	Hunterdon Co	86.5
New Jersey	Mercer Co	93.5
New Jersey	Middlesex Co	89.8
New Jersey	Ocean Co	98.0
New York	Erie Co	85.2
New York	Suffolk Co	89.9
Pennsylvania	Bucks Co	93.0
Pennsylvania	Montgomery Co	86.5
Pennsylvania	Philadelphia Co	88.9
Texas	Harris Co	97.3
Texas	Jefferson Co	85.0
Wisconsin	Kenosha Co	89.4

C. How Did EPA Assess Interstate Contributions to Nonattainment?

1. $PM_{2.5}$ Contribution Modeling Approach

For the proposed rule, EPA performed State-by-State zero-out modeling to quantify the contribution from emissions in each State to future $PM_{2.5}$ nonattainment in other States and to determine whether that contribution meets the air quality prong (*i.e.*, before considering cost) of the ''contribute significantly'' test. The zero-out modeling technique provides an estimate of downwind impacts by comparing the model predictions from the 2010 base case to the predictions from a run in which all anthropogenic SO_2 and NO_X emissions are removed from specific States. Counties forecast to be nonattainment for $PM_{2.5}$ in the proposal 2010 base case were used as receptors for quantifying interstate contributions of $PM_{2.5}$. For each State- by-State zero-out run we projected the annual average $PM_{2.5}$ concentration at each receptor using the proposed SMAT technique, as described in the NPR AQMTSD. The contribution from an upwind State to nonattainment at a given downwind receptor was determined by calculating the difference in $PM_{2.5}$ concentration between the 2010 base case and the zero-out run at that receptor. We followed this process for each State-by-State zero-out run and each receptor. For each upwind State, we identified the largest contribution from that State to a downwind nonattainment receptor in order to determine the magnitude of the maximum downwind contribution from each State. The maximum downwind contribution was proposed as the metric for determining whether or not the contribution was significant. As described in section III, EPA proposed, in the alternative, a criterion of 0.10 $\mu g/m^3$ and 0.15 $\mu g/m^3$ for determining whether emissions in a State make a significant contribution (before considering cost) to $PM_{2.5}$ nonattainment in another State. Details on these procedures can be found in the NPR AQMTSD.

Comments: Commenters questioned the use of zero-out modeling and said that EPA should support the development of a source apportionment model for $PM_{2.5}$ contributions. The commenter recommended that EPA delay the final rule until such a technique can be used. Another commenter provided results of a sulfate source apportionment technique currently under development along with modeling results which showed that the zero-out technique and source apportionment for sulfate provide similar results in terms of the magnitude and extent of downwind impacts. The commenter noted that the results suggest that zero-out modeling may somewhat underestimate the transport of sulfate.

Response: The EPA continues to believe that the zero-out technique is a credible method for quantifying interstate $PM_{2.5}$ contributions. This is supported by a commenter's results showing that the zero-out technique and source apportionment appear to give similar results. We accept the commenter's modeling for sulfate source apportionment results which indicate that the zero-out technique does not overestimate interstate transport. Moreover, EPA rejects the notion that we should delay needed reductions while we await alternative assessment techniques.

2. 8-Hour Ozone Contribution Modeling Approach

In the proposal, EPA quantified the impact of emissions from specific upwind States on 8-hour ozone concentrations in projected downwind nonattainment areas. The procedures we followed to assess interstate ozone contribution for the proposal analysis are summarized below. We are using these same procedures along with the updated CAM_X modeling platform, as described in section VI.A., to assess ozone contributions for today's rule. Details on these procedures can be found in the NFR AQMTSD.

We applied two different modeling techniques, zero-out and source apportionment, to assess the contributions of emissions in upwind States on 8-hour ozone nonattainment in downwind States. The outputs of the two modeling techniques were evaluated in terms of three key contribution factors to determine which States make a significant contribution to downwind ozone nonattainment as described in section VI.B.2. The zero-out and source apportionment modeling techniques provide different, but equally valid, technical approaches to quantifying the downwind impact of emissions from upwind States. The zero-out modeling analysis provides an estimate of downwind impacts by comparing the model predictions from the 2010 base case and the predictions from a model run in which all anthropogenic NO_X and VOC emissions are removed from specific States. The source apportionment modeling quantifies downwind impacts by tracking and allocating the amounts of ozone formed from man-made NO_X and VOC emissions in upwind States. Because large portions of the six States along the western border of the modeling domain [102] are outside the area covered by our modeling, EPA did not analyze the contributions to downwind ozone nonattainment for these States.

In the analysis done at proposal, EPA considered three fundamental factors for evaluating whether emissions in an upwind State make large and/or frequent contributions to downwind nonattainment: (1) The magnitude of the contribution; (2) the frequency of the contribution; and (3) the relative amount of the contribution when compared against contributions from other areas. The factors are the basis for several metrics that can be used to assess a particular impact. The metrics used in this analysis were the same as those used in the NO_X SIP Call.

Within these three factors, eight specific metrics were calculated to assess the contribution of each of the 31 States to the residual nonattainment counties. For the zero-out modeling, EPA considered: (1) The maximum contribution (magnitude); (2) the number and percentage of exceedances with contributions in certain concentration ranges (frequency); (3) the total contribution relative to the total exceedance level ozone in the receptor area (relative amount); and (4) the population-weighted total contribution relative to the total population-weighted exceedance level ozone in the receptor area (relative amount). For the source apportionment modeling EPA considered: (5) The maximum contribution (magnitude); (6) the highest daily average contribution (magnitude); (7) the number and percentages of exceedances with contributions in certain concentration ranges (frequency); and (8) the total average contribution to exceedance ozone in the downwind area (relative amount). The values for these metrics were calculated using only those periods during which the model predicted 8-hour average ozone concentrations greater than or equal to 85 ppb in at least one of the model grid cells associated with the receptor county in the 2010 base case. Grid cells were linked to a specific nonattainment county if any part of the grid cell covered any portion of the projected 2010 nonattainment county.

The first step in evaluating the contribution factors was to screen out linkages for which the contributions were clearly small. This initial screening was based on two criteria: (1) The maximum contribution had to be greater than or equal to 2 ppb from either of the two modeling techniques; and (2) the total average contribution to exceedance of ozone in the downwind area had to be greater than 1 percent. If either screening test was not met, then the linkage was not considered significant. Those linkages that had contributions which exceeded the screening criteria were evaluated further in steps 2 through 4.

In step 2, we evaluated the contributions in each linkage based on the zero-out modeling and in step 3 we evaluated the contributions in each linkage based on the source apportionment modeling. In step 4, we considered the results of both step 2 and step 3 to determine which of the linkages were significant. For both techniques, EPA determined whether the linkage is significant by evaluating the magnitude, frequency, and relative amount of the contributions. Each upwind State that made relatively large and/or frequent contributions to nonattainment in the downwind area, based on these factors, was considered to contribute significantly to nonattainment in the downwind area.

The EPA believes that each of the factors provides an independent measure of contribution, however, there had to be at least two different factors that indicated large and/or frequent contributions in order for the linkage to be found significant. In this regard, the finding of a significant contribution for an individual linkage was not based on any single factor. Further, each of the modeling approaches had to show at least one indicator of a large and/or frequent contribution in order for the linkage to be found significant. The EPA received several general comments on the procedures for assessing interstate contributions of ozone to projected residual nonattainment areas, as discussed below.

Comment: A commenter opposed the use of population-weighted metrics to determine whether an upwind State's impact on a location in another State is significant.

Response: The commenter's concern was that transport contributions to rural areas with low populations were not being weighted appropriately. This is not a valid concern because the relative contribution factor from the zero-out modeling is presumed to be met if either of the two criteria (population-weighted, or non-population-weighted) show large contributions.

Comment: Also, EPA received a specific comment on a certain linkage that was deemed to be significant in the analysis done to support the NPR. The commenter objected to the conclusion that Mississippi significantly contributes to residual ozone exceedances near Memphis. The objection resulted from issues with grid resolution, episode selection, and the fact that the zero-out and source apportionment modeling for Mississippi included some emissions from Tennessee and Arkansas due to the irregular State boundaries.

Response: As noted in section VI.B.2, Crittenden County, AR is no longer projected to be a nonattainment area in the 2010 base case. As a result, the issue of Mississippi's contribution to ozone in the Memphis area is moot.

D. What Are the Estimated Interstate Contributions to $PM_{2.5}$ and 8-Hour Ozone Nonattainment?

1. Results of $PM_{2.5}$ Contribution Modeling

In this section, we present the interstate contributions from emissions in upwind States to $PM_{2.5}$ nonattainment in downwind nonattainment counties. States which contribute 0.2 $\mu g/m^3$ or more to $PM_{2.5}$ nonattainment in another State are determined to contribute significantly (before considering cost). We calculated the interstate $PM_{2.5}$ contributions using the State-by-State zero-out modeling technique, as indicated above in section VI.C.1. This technique is described in

[102] The six States are Kansas, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.

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the NFR AQMTSD. We performed zero-out modeling using CMAQ for each of 37 States individually (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin).

We calculated each State's contribution to $PM_{2.5}$ in each of the 62 counties that are projected to be nonattainment in the 2010 base case (*i.e.*, "modeled" nonattainment) and are also "monitored" nonattainment in 2001–2003, as described in section VI.B.1.b. The maximum contribution from each upwind State to downwind $PM_{2.5}$ nonattainment is provided in Table VI–7. The contributions from each State to nonattainment in each nonattainment county are provided in the NFR AQMTSD. Based on the State-by-State modeling, there are 23 States and the District of Columbia [103] which contribute 0.2 μg/m³ or more to downwind $PM_{2.5}$ nonattainment (Alabama, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin). In Table VI–8, we provide a list of the downwind nonattainment counties to which each upwind State contributes 0.2 μg/m³ or more (*i.e.*, the upwind State-to-downwind nonattainment "linkages").

TABLE VI–7.—MAXIMUM DOWNWIND $PM_{2.5}$ CONTRIBUTION (μG/M³) FOR EACH OF 37 STATES

Upwind State	Maximum downwind contribution
Alabama	0.98
Arkansas	0.19
Connecticut	<0.05
Delaware	0.14
Florida	0.45
Georgia	1.27
Illinois	1.02
Indiana	0.91
Iowa	0.28
Kansas	0.11
Kentucky	0.90
Louisiana	0.25
Maine	<0.05
Maryland/DC	0.69
Massachusetts	0.07
Michigan	0.62
Minnesota	0.21
Mississippi	0.23
Missouri	1.07
Nebraska	0.07
New Hampshire	<0.05
New Jersey	0.13
New York	0.34
North Carolina	0.31
North Dakota	0.11
Ohio	1.67
Oklahoma	0.12
Pennsylvania	0.89
Rhode Island	<0.05
South Carolina	0.40
South Dakota	<0.05
Tennessee	0.65
Texas	0.29
Vermont	<0.05
Virginia	0.44
West Virginia	0.84
Wisconsin	0.56

TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR $PM_{2.5}$.

Upwind states	Total linkages	Downwind counties			
AL	21	Bibb GA	Cabell WV	Catawba NC	Clark IN.
		Clarke GA	Clayton GA	Cobb GA	Davidson NC.
		DeKalb GA	Dubois IN	Fayette KY	Floyd GA.
		Fulton GA	Hamilton OH	Hamilton TN	Jefferson KY.
		Knox TN	Lawrence OH	Scioto OH	Vanderburgh IN.
		Walker GA.			
FL	7	Bibb GA	Clarke GA	Clayton GA	Cobb GA.
		DeKalb GA	Jefferson AL	Russell AL.	
GA	17	Butler OH	Cabell WV	Catawba NC	Clark IN.
		Davidson NC	Fayette KY	Hamilton OH	Hamilton TN.
		Jefferson AL	Jefferson KY	Kanawha WV	Knox TN.
		Lawrence OH	Montgomery OH	Russell AL	Scioto OH.
		Vanderburgh IN.			
IL	23	Allegheny PA	Butler OH	Cabell WV	Clark IN.
		Cuyahoga OH	Dubois IN	Fayette KY	Franklin OH.
		Hamilton OH	Hamilton TN	Jefferson AL	Jefferson KY.
		Kanawha WV	Lake IN	Lawrence OH	Mahoning OH.
		Marion IN	Montgomery OH	Scioto OH	Stark OH.
		Summit OH	Vanderburgh IN	Wayne MI	
IN	46	Allegheny PA	Beaver PA	Berkeley WV	Bibb GA.
		Brooke WV	Butler OH	Cabell WV	Cambria PA.
		Catawba NC	Clarke GA	Clayton GA	Cobb GA.
		Cook IL	Cuyahoga OH	Davidson NC	DeKalb GA.
		Fayette KY	Floyd GA	Franklin OH	Fulton GA.
		Hamilton OH	Hamilton TN	Hancock WV	Jefferson AL.
		Jefferson KY	Jefferson OH	Kanawha WV	Knox TN.

[103] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties. The EPA received no adverse comment on this approach. We also considered these entities separately, and in view of the close proximity of these two areas we believe that Maryland is linked as a significant contributor to nonattainment in the District of Columbia and that the District of Columbia is linked as a significant contributor to nonattainment in Maryland.

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TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR $PM_{2.5}$.—Continued

		Lancaster PA	Lawrence OH	Madison IL	Mahoning OH.
		Marion WV	Marshall WV	Montgomery OH	Ohio WV.
		Russell AL	St. Clair IL	Scioto OH	Stark OH.
		Summit OH	Walker GA	Wayne MI	Washington PA.
		Westmoreland PA	Wood WV.		
IA	5	Cook IL	Lake IN	Madison IL	Marion IN.
		St. Clair IL.			
KY	35	Allegheny PA	Butler OH	Cabell WV	Catawba NC.
		Clark IN	Clarke GA	Cobb GA	Cuyahoga OH.
		Davidson NC	Dubois IN	Floyd GA	Franklin OH.
		Hamilton OH	Hamilton TN	Jefferson AL	Jefferson OH.
		Kanawha WV	Knox TN	Lawrence OH	Madison IL.
		Mahoning OH	Marion IN	Marion WV	Marshall WV.
		Montgomery OH	Ohio WV	St. Clair IL	Scioto OH.
		Stark OH	Summit OH	Vanderburgh IN	Walker GA.
		Washington PA	Westmoreland PA	Wood WV..	
LA	2	Jefferson AL	Russell AL.		
MD/DC	13	Berkeley WV	Berks PA	Cambria PA	Dauphin PA.
		Delaware PA	District of Columbia	Lancaster PA	New Castle DE.
		New York NY	Philadelphia PA	Union NJ	Westmoreland PA.
		York PA.			
MI	36	Allegheny PA	Beaver PA	Berks PA	Brooke WV.
		Butler OH	Cabell WV	Cambria PA	Clark IN.
		Cook IL	Cuyahoga OH	Dauphin PA	Delaware PA.
		Fayette KY	Franklin OH	Hamilton OH	Hancock WV.
		Jefferson OH	Lake IN	Lancaster PA	Lawrence OH.
		Mahoning OH	Marion IN	Marion WV	Marshall WV.
		Montgomery OH	New Castle DE	Ohio WV	Philadelphia PA.
		Scioto OH	Stark OH	Summit OH	Union NJ.
		Washington PA	Westmoreland PA	Wood WV	York PA.
MN	2	Cook IL	Lake IN.		
MO	9	Clark IN	Cook IL	Dubois IN	Jefferson KY.
		Lake IN	Madison IL	Marion IN	St. Clair IL.
		Vanderburgh IN..			
MS	1	Jefferson AL.			
NY	5	Berks PA	Lancaster PA	New Castle DE	New Haven CT.
		Union NJ.			
NC	7	Anne Arundel MD	Baltimore City	Bibb GA	Clarke GA.
		District of Columbia	Kanawha WV	Knox TN..	
OH	51	Anne Arundel MD	Allegheny PA	Baltimore City MD	Beaver PA.
		Berkeley WV	Berks PA	Bibb GA	Brooke WV.
		Cabell WV	Cambria PA	Catawba NC	Clark IN.
		Clarke GA	Clayton GA	Cobb GA	Cook IL.
		Dauphin PA	Davidson NC	DeKalb GA	Delaware PA.
		District of Columbia	Dubois IN	Fayette KY	Floyd GA.
		Fulton GA	Hamilton TN	Hancock WV	Jefferson AL.
		Jefferson KY	Kanawha WV	Knox TN	Lake IN.
		Lancaster PA	Madison IL	Marion IN	Marion WV.
		Marshall WV	New Castle DE	New York NY	Ohio WV.
		Philadelphia PA	Russell AL	St. Clair IL	Union NJ.
		Vanderburgh IN	Walker GA	Washington PA	Wayne MI.
		Westmoreland PA	Wood WV	York PA.	
PA	25	Anne Arundel MD	Baltimore City	Berkeley WV	Brooke WV.
		Cabell WV	Catawba NC	Clarke GA	Cuyahoga OH.
		Davidson NC	District of Columbia	Hancock WV	Jefferson OH.
		Kanawha WV	Lawrence OH	Mahoning OH	Marion WV.
		Marshall WV	New Castle DE	New York NY	Ohio WV.
		Stark OH	Summit OH	Union NJ	Wayne MI.
		Wood WV.			
SC	9	Bibb GA	Catawba NC	Clarke GA	Clayton GA.
		Cobb GA	Davidson NC	DeKalb GA	Fulton GA.
		Russell AL.			
TN	23	Bibb GA	Butler OH	Cabell WV	Catawba NC.
		Clark IN	Clarke GA	Clayton GA	Cobb GA.
		Davidson NC	DeKalb GA	Dubois IN	Fayette KY.
		Floyd GA	Fulton GA	Hamilton OH	Jefferson AL.
		Jefferson KY	Kanawha WV	Lawrence OH	Russell AL.
		Scioto OH	Vanderburgh TN	Walker GA.	
TX	2	Madison IL	St Clair IL.		
VA	13	Anne Arundel MD	Baltimore City MD	Berkeley WV	Berks PA.
		Catawba NC	Dauphin PA	Davidson NC	Delaware PA.
		District of Columbia	Lancaster PA	New Castle DE	Philadelphia PA.

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TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR $PM_{2.5}$.—Continued

		York PA.			
WV	33	Anne Arundel MD	Allegheny PA	Baltimore City MD	Beaver PA.
		Berks PA	Butler OH	Cambria PA	Catawba NC.
		Clarke GA	Cuyahoga OH	Dauphin PA	Davidson NC.
		Delaware PA	District of Columbia	Fayette KY	Franklin OH.
		Hamilton OH	Jefferson OH	Knox TN	Lancaster PA.
		Lawrence OH	Mahoning OH	Montgomery OH	New Castle DE.
		New York NY	Philadelphia PA	Scioto OH	Stark OH.
		Summit OH	Union NJ	Washington PA	Westmoreland PA.
		York PA.			
WI	4	Cook IL	Lake IN	Marion IN	Wayne MI.

2. Results of 8-Hour Ozone Contribution Modeling

In this section, we present the results of air quality modeling to determine which upwind States contribute significantly (before considering cost) to 8-hour ozone nonattainment in downwind States. The analytical procedures to determine which States make a significant contribution are based on the zero-out and source apportionment modeling techniques using CAMx, as described in section VI.C.2 and in the NFR AQMTSD. We performed ozone contribution modeling using both of these techniques for 31 States in the East and the District of Columbia (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, Georgia, Florida, Iowa, Illinois, Indiana, Kentucky, Louisiana, Massachusetts, Maine, Maryland combined with the District of Columbia, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin).

We evaluated the interstate ozone contributions from each of the 31 upwind States and the District of Columbia to each of the 40 counties that are projected to be nonattainment in the 2010 base case (*i.e.*, "modeled" nonattainment) and are also "monitored" nonattainment in 2001–2003, as described in section VI.B.2.b. We analyzed the contributions from upwind States to these counties in terms of various metrics, described above and in more detail in the NFR AQMTSD.

Based on the State-by-State modeling, there are 25 States and the District of Columbia [104] which make a significant contribution (before considering cost) to 8-hour ozone nonattainment in downwind States (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Iowa, Illinois, Indiana, Kentucky, Louisiana, Massachusetts, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin). In Table VI–9, we provide a list of the downwind nonattainment counties to which each upwind State makes a significant contribution (*i.e.*, the upwind State-to-downwind nonattainment "linkages").

TABLE VI–9.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR 8-HOUR OZONE.

Upwind states	Total linkages	Downwind counties			
AL	3	Fulton GA	Harris TX	Jefferson TX.	
AR	3	Galveston TX	Harris TX	Jefferson TX.	
CT	2	Kent RI	Suffolk NY.		
DE	13	Bucks PA	Camden NJ	Chester PA	Gloucester NJ.
		Hunterdon NJ	Mercer NJ	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	Ocean NJ	Philadelphia PA.
		Suffolk NY.			
FL	1	Fulton GA			
IA	3	Kenosha WI	Macomb MI	Sheboygan WI.	
IL	5	Geauga OH	Kenosha WI	Macomb MI	Ozaukee WI.
		Sheboygan WI.			
IN	5	Geauga OH	Kenosha WI	Macomb MI	Ozaukee WI.
		Sheboygan WI..			
KY	3	Fulton GA	Geauga OH	Macomb MI.	
LA	3	Galveston TX	Harris TX	Jefferson TX.	
MA	2	Kent RI	Middlesex NJ.		
MD/DC	23	Arlington VA	Bergen NJ	Bucks PA	Camden NJ.
		Chester PA	District of Columbia	Erie NY	Fairfax VA.
		Fairfield CT	Gloucester NJ	Hunterton NJ	Mercer NJ.
		Middlesex NJ	Monmouth NJ	Montgomery PA	Morris NJ.

[104] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties. The EPA received no adverse comment on this approach. We also considered these entities separately, and in view of the close proximity of these two areas we believe that Maryland is linked as a significant contributor to nonattainment in the District of Columbia and that the District of Columbia is linked as a significant contributor to nonattainment in Maryland.

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TABLE VI–9.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR 8-HOUR OZONE.—Continued

		New Castle DE	New Haven CT	Ocean NJ	Philadelphia PA.
		Richmond NY	Suffolk NY	Westchester NY	
MI	19	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	Erie NY	Geauga OH.
		Gloucester NJ	Kent MD	Mercer NJ	Middlesex NJ.
		Monmouth NJ	Morris NJ	New Castle DE	Ocean NJ.
		Philadelphia PA	Richmond NY	Suffolk NY	
MO	4	Geauga OH	Kenosha WI	Ozaukee WI	Sheboygan WI.
MS	2	Harris TX	Jefferson TX.		
NC	8	Anne Arundel MD	Fulton GA	Harford MD	Kent MD.
		Newcastle DE	Suffolk NY	Bucks PA	Chester PA.
NJ	10	Erie NY	Fairfield CT	Kent RI	Middlesex CT.
		Montgomery PA	New Haven CT	Philadelphia PA	Richmond NY.
		Suffolk NY	Westchester NY.		
NY	9	Fairfield CT	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Haven CT.
		Ocean NJ.			
		Anne Arundel MD	Arlington VA	Bergen NJ	Bucks PA.
OH	28	Camden NJ	Cecil MD	Chester PA	District of Columbia.
		Fairfax VA	Fairfield CT	Gloucester NJ	Harford MD.
		Hunterton NJ	Kent MD	Kent RI	Macomb MI.
		Mercer NJ	Middlesex CT	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	New Castle DE	New Haven CT.
		Ocean NJ	Philadelphia PA	Suffolk NY	Westchester NY.
PA	25	Anne Arundel MD	Arlington VA	Bergen NJ	Camden NJ.
		Cecil MD	District of Columbia	Erie NY	Fairfax VA.
		Fairfield CT	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Castle DE.
		New Haven CT	Ocean NJ	Richmond NY	Suffolk NY.
		Westchester NY.			
SC	1	Fulton GA.			
TN	1	Fulton GA.			
VA	26	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	District of Columbia	Erie NY.
		Fairfield CT	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Castle DE.
		New Haven CT	Ocean NJ	Philadelphia PA	Richmond NY.
		Suffolk NY	Westchester NY.		
WI	2	Erie NY	Macomb MI.		
WV	25	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	Fairfax VA	Fairfield CT.
		Fulton GA	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Mercer NJ	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	New Castle DE	New Haven CT.
		Ocean NJ	Philadelphia PA	Richmond NY	Suffolk NY.
		Westchester NY.			

E. What are the Estimated Air Quality Impacts of the Final Rule?

In this section, we describe the air quality modeling performed to determine the projected impacts on $PM_{2.5}$ and 8-hour ozone of the SO_2 and NO_X emissions reductions in the control region modeled. The modeling used to estimate the air quality impact of these reductions assumes annual SO_2 and NO_X controls for Arkansas, Delaware, and New Jersey in addition to the 23-States plus the District of Columbia. Since Arkansas, Delaware, and New Jersey are not included in the final CAIR region for $PM_{2.5}$, the modeled estimated impacts on $PM_{2.5}$ are overstated for today's final rule. However, EPA plans to include Delaware and New Jersey in the CAIR region for $PM_{2.5}$ through a separate regulatory process. Thus, the estimates are reflective of the total impacts expected for CAIR assuming Delaware and New Jersey will become part of the annual SO_2 and NO_X trading programs.

As discussed in section IV, EPA analyzed the impacts of the regional emissions reductions in both 2010 and 2015. These impacts are quantified by comparing air quality modeling results for the regional control scenario to the modeling results for the corresponding 2010 and 2015 base case scenarios. The 2010 and 2015 emissions reductions from the power generation sector include a two-phase cap and trade program covering the control region modeled (*i.e.*, the 23 States plus the District of Columbia included in today's rule and Arkansas, Delaware, and New Jersey).[105] Phase 1 of the regional strategy (the 2010 reductions) is forecast to reduce total EGU SO_2 emissions [106] in

[105] In addition to the SO_2 and NO_X reductions in these States, we also modeled summer-season only EGU NO_X controls for Connecticut and Massachusetts, which significantly contribute to ozone, but not to $PM_{2.5}$ nonattainment in downwind areas.

[106] For the purposes of this discussion, we have calculated the percent reduction in total EGU

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the control region modeled by 40 percent in 2010. Phase 2 (the 2015 reductions) is forecast to provide a 48 percent reduction in EGU SO_2 emissions compared to the base case in 2015. When fully implemented post-2015, we expect this rule to result in more than a 70 percent reduction in EGU SO_2 emissions compared to current emissions levels. The reductions at full implementation occur post-2015 due to the existing title IV bank of SO_2 allowances, which can be used under the CAIR program. The net effect of the strategy on total SO_2 emissions in the control region modeled considering all sources of emissions, is a 28 percent reduction in 2010 and a 32 percent reduction in 2015.

For NO_X, Phase 1 of the strategy is forecast to reduce total EGU emissions by 44 percent in 2009. Total NO_X emissions across the control region (*i.e.*, includes all sources) are 11 percent lower in the 2010 CAIR scenario compared to the emissions in the 2010 base case. In Phase 2, EGU NO_X emissions are projected to decline by 54 percent in 2015 in this region. Total NO_X emissions from all anthropogenic sources are projected to be reduced by 14 percent in 2015. The percent change in emissions by State for SO_2 and NO_X in 2010 and 2015 for the regional control strategy modeled are provided in the NFR EITSD.

1. Estimated Impacts on $PM_{2.5}$ Concentrations and Attainment

We determined the impacts on $PM_{2.5}$ of the CAIR regional strategy by running the CMAQ model for this strategy and comparing the results to the $PM_{2.5}$ concentrations predicted for the 2010 and 2015 base cases. In brief, we ran the CMAQ model for the regional strategy in both 2010 and 2015. The model predictions were used to project future $PM_{2.5}$ concentrations for CAIR in 2010 and 2015 using the SMAT technique, as described in section VI.B.1. We compared the results of the 2010 and 2015 regional strategy modeling to the corresponding results from the 2010 and 2015 base cases to quantify the expected impacts of CAIR.

The impacts of the SO_2 and NO_X emissions reductions expected from CAIR on $PM_{2.5}$ in 2010 and 2015 are provided in Table VI–10 and Table VI–11, respectively. In these tables, counties shown in bold/italics are projected to come into attainment with CAIR.

TABLE VI–10.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M³) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010

State	County	2010 Base case	2010 CAIR	Impact of CAIR
Alabama	DeKalb Co	15.23	13.97	¥1.26
Alabama	Jefferson Co	18.57	17.46	¥1.11
Alabama	Montgomery Co	15.12	14.10	¥1.02
Alabama	Morgan Co	15.29	14.11	¥1.18
Alabama	Russell Co	16.17	15.15	¥1.02
Alabama	Talladega Co	15.34	14.00	¥1.34
Delaware	New Castle Co	16.56	14.84	¥1.72
District of Columbia		15.84	13.68	¥2.16
Georgia	Bibb Co	16.27	15.17	¥1.10
Georgia	Clarke Co	16.39	14.96	¥1.43
Georgia	Clayton Co	17.39	16.29	¥1.10
Georgia	Cobb Co	16.57	15.35	¥1.22
Georgia	DeKalb Co	16.75	15.70	¥1.05
Georgia	Floyd Co	16.87	15.87	¥1.00
Georgia	Fulton Co	18.02	16.98	¥1.04
Georgia	Hall Co	15.60	14.28	¥1.32
Georgia	Muscogee Co	15.65	14.57	¥1.08
Georgia	Richmond Co	15.68	14.64	¥1.04
Georgia	Walker Co	15.43	14.22	¥1.21
Georgia	Washington Co	15.31	14.22	¥1.09
Georgia	Wilkinson Co	16.27	15.22	¥1.05
Illinois	Cook Co	17.52	16.88	¥0.64
Illinois	Madison Co	16.66	15.96	¥0.70
Illinois	St. Clair Co	16.24	15.54	¥0.70
Indiana	Clark Co	16.51	15.15	¥1.36
Indiana	Dubois Co	15.73	14.37	¥1.36
Indiana	Lake Co	17.26	16.48	¥0.78
Indiana	Marion Co	16.83	15.54	¥1.29
Indiana	Vanderburgh Co	15.54	14.26	¥1.28
Kentucky	Boyd Co	15.23	13.38	¥1.85
Kentucky	Bullitt Co	15.10	13.67	¥1.43
Kentucky	Fayette Co	15.95	14.17	¥1.78
Kentucky	Jefferson Co	16.71	15.44	¥1.27
Kentucky	Kenton Co	15.30	13.72	¥1.58
Maryland	Anne Arundel Co	15.26	12.98	¥2.28
Maryland	Baltimore city	16.96	14.88	¥2.08
Michigan	Wayne Co	19.41	18.23	¥1.18
Missouri	St. Louis City	15.10	14.40	¥0.70
New Jersey	Union Co	15.05	13.60	¥1.45
New York	New York Co	16.19	14.95	¥1.24
North Carolina	Catawba Co	15.48	14.07	¥1.41
North Carolina	Davidson Co	15.76	14.36	¥1.40

emissions which includes units greater than and less than 25 MW.

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TABLE VI–10.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu g/m^3$) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010—Continued

State	County	2010 Base case	2010 CAIR	Impact of CAIR
North Carolina	Mecklenburg Co	15.22	13.92	¥1.30
Ohio	Butler Co	16.45	15.03	¥1.42
Ohio	Cuyahoga Co	18.84	17.11	¥1.73
Ohio	Franklin Co	16.98	15.13	¥1.85
Ohio	Hamilton Co	18.23	16.61	¥1.62
Ohio	Jefferson Co	17.94	15.64	¥2.30
Ohio	Lawrence Co	16.10	14.11	¥1.99
Ohio	Mahoning Co	15.39	13.40	¥1.99
Ohio	Montgomery Co	15.41	13.83	¥1.58
Ohio	Scioto Co	18.13	15.98	¥2.15
Ohio	Stark Co	17.14	15.08	¥2.06
Ohio	Summit Co	16.47	14.69	¥1.78
Ohio	Trumbull Co	15.28	13.50	¥1.78
Pennsylvania	Allegheny Co	20.55	18.01	¥2.54
Pennsylvania	Beaver Co	15.78	13.61	¥2.17
Pennsylvania	Berks Co	15.89	13.56	¥2.33
Pennsylvania	Cambria Co	15.14	12.72	¥2.42
Pennsylvania	Dauphin Co	15.17	12.88	¥2.29
Pennsylvania	Delaware Co	15.61	13.94	¥1.67
Pennsylvania	Lancaster Co	16.55	14.09	¥2.46
Pennsylvania	Philadelphia Co	16.65	14.98	¥1.67
Pennsylvania	Washington Co	15.23	12.99	¥2.24
Pennsylvania	Westmoreland Co	15.16	12.60	¥2.56
Pennsylvania	York Co	16.49	14.20	¥2.29
Tennessee	Davidson Co	15.36	14.26	¥1.10
Tennessee	Hamilton Co	16.89	15.57	¥1.32
Tennessee	Knox Co	17.44	16.16	¥1.28
Tennessee	Sullivan Co	15.32	14.01	¥1.31
West Virginia	Berkeley Co	15.69	13.43	¥2.26
West Virginia	Brooke Co	16.63	14.42	¥2.21
West Virginia	Cabell Co	17.03	15.08	¥1.95
West Virginia	Hancock Co	17.06	14.89	¥2.17
West Virginia	Kanawha Co	17.56	15.27	¥2.29
West Virginia	Marion Co	15.32	12.90	¥2.42
West Virginia	Marshall Co	15.81	13.46	¥2.35
West Virginia	Ohio Co	15.14	12.81	¥2.33
West Virginia	Wood Co	16.66	14.14	¥2.52

TABLE VI–11.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu g/m^3$) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Alabama	DeKalb Co	15.24	13.46	¥1.78
Alabama	Jefferson Co	18.85	17.36	¥1.49
Alabama	Montgomery Co	15.24	13.87	¥1.37
Alabama	Morgan Co	15.26	13.85	¥1.41
Alabama	Russell Co	16.10	14.66	¥1.44
Alabama	Talladega Co	15.22	13.35	¥1.87
Delaware	New Castle Co	16.47	14.41	¥2.06
District of Columbia		15.57	13.11	¥2.46
Georgia	Bibb Co	16.41	14.83	¥1.58
Georgia	Chatham Co	15.06	13.86	¥1.20
Georgia	Clarke Co	16.15	14.10	¥2.05
Georgia	Clayton Co	17.46	15.85	¥1.61
Georgia	Cobb Co	16.51	14.67	¥1.84
Georgia	DeKalb Co	16.82	15.29	¥1.53
Georgia	Floyd Co	17.33	15.79	¥1.54
Georgia	Fulton Co	18.00	16.47	¥1.53
Georgia	Hall Co	15.36	13.48	¥1.88
Georgia	Muscogee Co	15.58	14.06	¥1.52
Georgia	Richmond Co	15.76	14.23	¥1.53
Georgia	Walker Co	15.37	13.65	¥1.72
Georgia	Washington Co	15.34	13.67	¥1.67
Georgia	Wilkinson Co	16.54	15.01	¥1.53
Illinois	Cook Co	17.71	16.95	¥0.76
Illinois	Madison Co	16.90	16.07	¥0.83
Illinois	St. Clair Co	16.49	15.64	¥0.85

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TABLE VI–11.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu G/M^3$) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015—Continued

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Illinois	Will Co	15.12	14.27	¥0.85
Indiana	Clark Co	16.37	14.79	¥1.58
Indiana	Dubois Co	15.66	14.16	¥1.50
Indiana	Lake Co	17.27	16.36	¥0.91
Indiana	Marion Co	16.77	15.38	¥1.39
Indiana	Vanderburgh Co	15.56	14.17	¥1.39
Kentucky	Boyd Co	15.06	12.95	¥2.11
Kentucky	Fayette Co	15.62	13.54	¥2.08
Kentucky	Jefferson Co	16.61	15.13	¥1.48
Kentucky	Kenton Co	15.09	13.26	¥1.83
Maryland	Baltimore city	17.04	14.50	¥2.54
Maryland	Baltimore Co	15.08	12.75	¥2.33
Michigan	Wayne Co	19.28	17.95	¥1.33
Mississippi	Jones Co	15.18	14.06	¥1.12
Missouri	St. Louis city	15.34	14.50	¥0.84
New York	New York Co	15.76	14.33	¥1.43
North Carolina	Catawba Co	15.19	13.45	¥1.74
North Carolina	Davidson Co	15.34	13.61	¥1.73
Ohio	Butler Co	16.32	14.67	¥1.65
Ohio	Cuyahoga Co	18.60	16.67	¥1.93
Ohio	Franklin Co	16.64	14.57	¥2.07
Ohio	Hamilton Co	18.03	16.10	¥1.93
Ohio	Jefferson Co	17.83	15.26	¥2.57
Ohio	Lawrence Co	15.92	13.71	¥2.21
Ohio	Mahoning Co	15.13	12.94	¥2.19
Ohio	Montgomery Co	15.16	13.33	¥1.83
Ohio	Scioto Co	17.92	15.55	¥2.37
Ohio	Stark Co	16.86	14.58	¥2.28
Ohio	Summit Co	16.14	14.18	¥1.96
Ohio	Trumbull Co	15.05	13.08	¥1.97
Pennsylvania	Allegheny Co	20.33	17.47	¥2.86
Pennsylvania	Beaver Co	15.54	13.09	¥2.45
Pennsylvania	Berks Co	15.66	12.99	¥2.67
Pennsylvania	Delaware Co	15.52	13.52	¥2.00
Pennsylvania	Lancaster Co	16.28	13.33	¥2.95
Pennsylvania	Philadelphia Co	16.53	14.53	¥2.00
Pennsylvania	York Co	16.22	13.46	¥2.76
Tennessee	Davidson Co	15.36	14.02	¥1.34
Tennessee	Hamilton Co	16.82	14.94	¥1.88
Tennessee	Knox Co	17.34	15.61	¥1.73
Tennessee	Shelby Co	15.17	14.19	¥0.98
Tennessee	Sullivan Co	15.37	13.77	¥1.60
West Virginia	Berkeley Co	15.32	12.73	¥2.59
West Virginia	Brooke Co	16.51	14.05	¥2.46
West Virginia	Cabell Co	16.86	14.64	¥2.22
West Virginia	Hancock Co	16.97	14.54	¥2.43
West Virginia	Kanawha Co	17.17	14.66	¥2.51
West Virginia	Marshall Co	15.52	12.87	¥2.65
West Virginia	Wood Co	16.69	13.88	¥2.81

As described in section VI.B.1, we project that 79 counties in the East will be nonattainment for $PM_{2.5}$ in the 2010 base case. We estimate that, on average, the regional strategy will reduce $PM_{2.5}$ in these 79 counties by 1.6 $\mu g/m^3$. In over 90 percent of the nonattainment counties (*i.e.*, 74 out of 79 counties), we project that $PM_{2.5}$ will be reduced by at least 1.0 $\mu g/m^3$. In over 25 percent of the 79 nonattainment counties (*i.e.*, 23 of the 79 counties), we project $PM_{2.5}$ concentrations will decline by of more than 2.0 $\mu g/m^3$. Of the 79 counties that are nonattainment in the 2010 Base, we project that 51 counties will come into attainment as a result of the SO_2 and NO_X emissions reductions expected from the regional controls. Even those 28 counties that remain nonattainment in 2010 after implementation of the regional strategy will be closer to attainment as a result of these emissions reductions. Specifically, the average reduction of $PM_{2.5}$ in the 28 residual nonattainment counties is projected to be 1.3 $\mu g/m^3$. After implementation of the regional controls, we project that 18 of the 28 residual nonattainment counties in 2010 will be within 1.0 $\mu g/m^3$ of the NAAQS and 12 counties will be within 0.5 $\mu g/m^3$ of attainment.

In 2015 we are projecting that $PM_{2.5}$ in the 74 base case nonattainment counties will be reduced by 1.8 $\mu g/m^3$, on average, as a result of the SO_2 and NO_X reductions in the regional strategy. In over 90 percent of the nonattainment counties (*i.e.*, 67 of the 74 counties) concentrations of $PM_{2.5}$ are predicted to be reduced by at least 1.0 $\mu g/m^3$. In over 35 percent of the counties (*i.e.*, 27 of the 74 counties), we project the regional strategy to reduce $PM_{2.5}$ by more than 2.0 $\mu g/m^3$. As a result of the reductions in $PM_{2.5}$, 56 nonattainment counties are projected to come into attainment in 2015. The remaining 18 nonattainment counties are projected to be closer to attainment with the regional strategy. Our modeling results indicate that $PM_{2.5}$ will be reduced in the range of 0.7 μg/m^3 to 2.9 μg/m^3 in these 18 counties. The average reduction across these 18 residual nonattainment counties is 1.5 μg/m^3.

Thus, the SO_2 and NO_X emissions reductions which will result from the regional strategy will greatly reduce the extent of $PM_{2.5}$ nonattainment by 2010 and beyond. These emissions reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment counties in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in these residual nonattainment counties.

2. Estimated Impacts on 8-Hour Ozone Concentrations and Attainment

We determined the impacts on 8-hour ozone of the regional strategy by running the CAM_X model for this strategy and comparing the results to the ozone concentrations predicted for the 2010 and 2015 base cases. In brief, we ran the CAM_X model for the regional strategy in both 2010 and 2015. The model predictions were used to project future 8-hour ozone concentrations for the regional strategy in 2010 and 2015 using the Relative Reduction Factor technique, as described in section VI.B.1. We compared the results of the 2010 and 2015 regional strategy modeling to the corresponding results from the 2010 and 2015 base cases to quantify the expected impacts of the regional controls.

The results of the regional strategy ozone modeling are expressed in terms of the expected reductions in projected 8-hour concentrations and the implications for future nonattainment. The impacts of the regional NO_X emissions reductions on 8-hour ozone in 2010 and 2015 are provided in Table VI–12 and Table VI–13, respectively. In these tables, counties shown in bold/italics are projected to come into attainment with the regional controls.

TABLE VI–12.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010

State	County	2010 Base case	2010 CAIR	Impact of CAIR
Connecticut	Fairfield Co	92.6	92.2	¥0.4
Connecticut	Middlesex Co	90.9	90.6	¥0.3
Connecticut	New Haven Co	91.6	91.3	¥0.3
District of Columbia	District of Columbia	85.2	85.0	¥0.2
Delaware	New Castle Co	85.0	84.7	¥0.3
Georgia	Fulton Co	86.5	85.1	¥1.4
Maryland	Anne Arundel Co	88.8	88.6	¥0.2
Maryland	Cecil Co	89.7	89.5	¥0.2
Maryland	Harford Co	93.0	92.8	¥0.2
Maryland	Kent Co	86.2	85.8	¥0.4
Michigan	Macomb Co	85.5	85.4	¥0.1
New Jersey	Bergen Co	86.9	86.0	¥0.9
New Jersey	Camden Co	91.9	91.6	¥0.3
New Jersey	Gloucester Co	91.8	91.3	¥0.5
New Jersey	Hunterdon Co	89.0	88.6	¥0.4
New Jersey	Mercer Co	95.6	95.2	¥0.4
New Jersey	Middlesex Co	92.4	92.1	¥0.3
New Jersey	Monmouth Co	86.6	86.4	¥0.2
New Jersey	Morris Co	86.5	85.5	¥1.0
New Jersey	Ocean Co	100.5	100.3	¥0.2
New York	Erie Co	87.3	86.9	¥0.4
New York	Richmond Co	87.3	87.1	¥0.2
New York	Suffolk Co	91.1	90.8	¥0.3
New York	Westchester Co	85.3	84.7	¥0.6
Ohio	Geauga Co	87.1	86.6	¥0.5
Pennsylvania	Bucks Co	94.7	94.3	¥0.4
Pennsylvania	Chester Co	85.7	85.4	¥0.3
Pennsylvania	Montgomery Co	88.0	87.6	¥0.4
Pennsylvania	Philadelphia Co	90.3	89.9	¥0.4
Rhode Island	Kent Co	86.4	86.2	¥0.2
Texas	Denton Co	87.4	86.8	¥0.6
Texas	Galveston Co	85.1	84.6	¥0.5
Texas	Harris Co	97.9	97.4	¥0.5
Texas	Jefferson Co	85.6	85.0	¥0.6
Texas	Tarrant Co	87.8	87.2	¥0.6
Virginia	Arlington Co	86.2	86.0	¥0.2
Virginia	Fairfax Co	85.7	85.4	¥0.3
Wisconsin	Kenosha Co	91.3	91.0	¥0.3
Wisconsin	Ozaukee Co	86.2	85.8	¥0.4
Wisconsin	Sheboygan Co	88.3	87.7	¥0.6

TABLE VI–13.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Connecticut	Fairfield Co	91.4	90.6	¥0.8

TABLE VI–13.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015—Continued

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Connecticut	Middlesex Co	89.1	88.4	¥0.7
Connecticut	New Haven Co	89.8	89.1	¥0.7
Maryland	Anne Arundel Co	86.0	84.9	¥1.1
Maryland	Cecil Co	86.9	85.4	¥1.5
Maryland	Harford Co	90.6	89.6	¥1.0
Michigan	Macomb Co	85.1	84.2	¥0.9
New Jersey	Bergen Co	85.7	84.5	¥1.2
New Jersey	Camden Co	89.5	88.3	¥1.2
New Jersey	Gloucester Co	89.6	88.2	¥1.4
New Jersey	Hunterdon Co	86.5	85.4	¥1.1
New Jersey	Mercer Co	93.5	92.4	¥1.1
New Jersey	Middlesex Co	89.8	88.8	¥1.0
New Jersey	Ocean Co	98.0	96.9	¥1.1
New York	Erie Co	85.2	84.2	¥1.0
New York	Suffolk Co	89.9	89.0	¥0.9
Pennsylvania	Bucks Co	93.0	91.8	¥1.2
Pennsylvania	Montgomery Co	86.5	84.9	¥1.6
Pennsylvania	Philadelphia Co	88.9	87.5	¥1.4
Texas	Harris Co	97.3	96.4	¥0.9
Texas	Jefferson Co	85.0	84.1	¥0.9
Wisconsin	Kenosha Co	89.4	88.8	¥0.6

As described in section VI.B.1, we project that 40 counties in the East would be nonattainment for 8-hour ozone under the assumptions in the 2010 base case. Our modeling of the regional controls in 2010 indicates that 3 of these counties will come into attainment of the 8-hour ozone NAAQS and that ozone in 16 of the 40 nonattainment counties will be reduced by 1 ppb or more. In addition, our modeling predicts that 8-hour ozone exceedances (*i.e.*, 8-hour ozone of 85 ppb or higher) within nonattainment areas are expected to decline by 5 percent in 2010 with CAIR. Of the 37 counties that are projected to remain nonattainment in 2010 after the regional strategy, nearly half (*i.e.*, 16 of the 37 counties) are within 2 ppb of attainment.

In 2015, we project that 6 of the 22 counties which are nonattainment for 8-hour ozone in the base case will come into attainment with the regional strategy. Ozone concentrations in over 70 percent (*i.e.*, 16 of 22 counties) of the 2015 base case nonattainment counties are projected to be reduced by 1 ppb or more as a result of the regional strategy. Exceedances of the 8-hour ozone NAAQS are predicted to decline in nonattainment areas by 14 percent with regional controls in place in 2015. Thus, the NO_X emissions reductions which will result from the regional strategy will help to bring 8-hour ozone nonattainment areas in the East closer to attainment by 2010 and beyond.

F. What are the Estimated Visibility Impacts of the Final Rule?

1. Methods for Calculating Projected Visibility in Class I Areas

The NPR contained example future year visibility projections for the 20 percent worst days and 20 percent best days at Class I areas that had complete IMPROVE monitoring data in 1996. Changes in future visibility were predicted by using the REMSAD model to generate relative visibility changes, then applying those changes to measured current visibility data. Details of the visibility modeling and calculations can be found in the NPR AQMTSD. An example visibility calculation was given in Appendix M of the NPR AQMTSD along with the predicted improvement in visibility (in deciviews) on the 20 percent best and worst days at 44 Class I areas. The data contained in Appendix M was for informational purposes only and was not used in the significant contribution determination or control strategy development decisions.

The SNPR contained visibility calculations in support of the ''better-than-BART'' analysis. The better-than-BART analysis employed a two-pronged test to determine if the modeled visibility improvements from the CAIR cap and trade program for EGU's were ''better'' than the visibility improvements from a nationwide BART program. The analysis used the visibility calculation methodology detailed in the NPR TSD. Detailed results of the SNPR better-than-BART analysis are contained in the SNPR AQMTSD. The better-than-BART analysis for the final rule is addressed in section IX.C.2 of the preamble. Additional information on the visibility calculation methodology is contained in the NFR AQMTSD.

2. Visibility Improvements in Class I Areas

For the NFR we have modeled several new CAIR [107] and CAIR + BART cases to re-examine the better-than-BART two-pronged test. We have modeled an updated nationwide BART scenario as well as a CAIR in the East/BART in the West scenario. The results were analyzed at 116 Class I areas that have complete IMPROVE data for 2001 or are represented by IMPROVE monitors with complete data. Twenty-nine of the Class I areas are in the East and 87 are in the West. The results of the visibility analysis are summarized in section IX.C.2. Detailed results for all 116 Class I areas are presented in the NFR AQMTSD.

VII. SIP Criteria and Emissions Reporting Requirements

This section describes: (1) The criteria we will use in determining approvability of SIPs submitted to meet the requirements of today's rulemaking; (2) the dates for submittal of the SIPs that are required under the CAIR; (3) the consequences of either failing to submit such a SIP or submitting a SIP which is

[107] The CAIR scenario modeled for the visibility analysis included controls in Arkansas, Delaware, and New Jersey.

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disapproved; and (4) the emissions inventory reporting requirements for States.

A. What Criteria Will EPA Use To Evaluate the Approvability of a Transport SIP?

1. Introduction

The approvability criteria for CAIR SIP submissions are finalized today in 40 CFR 51.123 (NO_X emissions reductions) and in 40 CFR 51.124 (SO_2 emissions reductions). Most of the criteria are substantially similar to those that currently apply to SIP submissions under CAA section 110 or part D (nonattainment). For example, each submission must describe the control measures that the State intends to employ, identify the enforcement methods for monitoring compliance and managing violations, and demonstrate that the State has legal authority to carry out its plan.

This part of the preamble explains additional approvability criteria specific to the CAIR that were proposed and discussed in the CAIR NPR or in the CAIR SNPR, and are being promulgated today. As explained in both the CAIR NPR and the CAIR SNPR, EPA proposed that each affected State must submit SIP revisions containing control measures that assure that a specified amount of NO_X and SO_2 emissions reductions are achieved by specified dates.

Although EPA determined the amount of emissions reductions required by identifying specific, highly cost-effective control levels for EGUs, EPA explained in the CAIR NPR and the CAIR SNPR that States have flexibility in choosing which sources to control to achieve the required emissions reductions. As long as a State's emissions reductions requirements are met, a State may impose controls on EGUs only, on non-EGUs only, or on a combination of EGUs and non-EGUs. The SIP approvability criteria are intended to provide as much certainty as possible that, whichever sources a State chooses to control, the controls will result in the required amount of emissions reductions.

In the CAIR NPR, EPA proposed a ''hybrid'' approach for the mechanisms used to ensure emissions reductions are achieved. This approach incorporates elements of an emissions ''budget'' approach (requiring an emissions cap on affected sources) and an ''emissions reduction'' approach (not requiring an emissions cap). In this hybrid approach, if States impose control measures on EGUs, they would be required to impose an emissions cap on all EGUs, which would effectively be an emissions budget. And, as stated in the CAIR NPR, if States impose control measures on non-EGUs, they would be encouraged but not required to impose an emissions cap on non-EGUs. In the CAIR NPR, we requested comment on the issue of requiring States to impose caps on any source categories that the State chooses to regulate.

In the CAIR SNPR, we proposed to modify the hybrid approach and require States that choose to control large industrial boilers or turbines (greater than 250 MMBTU/hr) to impose an emissions cap on all such sources within their State. This is similar to EPA's approach in the NO_X SIP Call which required States to include an emissions cap on such sources as well as on EGUs if the SIP submittals included controls on such sources. (See 40 CFR 51.121(f)(2)(ii).)

A few commenters supported the use of emissions caps on any source category subject to CAIR controls, including non-EGUs, because it would be the most effective way to demonstrate compliance with the budget. A few other commenters opposed the use of an emissions cap on non-EGUs, saying either that States should have the flexibility to determine whether to impose a cap, or that such a requirement would result in increased costs for non-EGUs including cogeneration units that are non-EGUs. No commenter opposing such a requirement provided any information indicating that such a requirement would be ineffective or impracticable. Today EPA is adopting the modified approach, as described in the CAIR SNPR, that States choosing to control EGUs or large industrial boilers or turbines must do so by imposing an emissions cap on such sources, similar to what was required in the NO_X SIP Call.

Extensive comments were received regarding the need for an ozone season NO_X cap in States identified to be contributing significantly to the region's ozone nonattainment problems. In proposal, EPA stated that the annual NO_X cap under CAIR reduced NO_X emissions sufficiently enough to not warrant a regional ozone season NO_X cap. Commenters remained very concerned that the annual NO_X cap would not aid ozone attainment. While EPA feels that the annual NO_X limit will most likely be protective in the ozone season, a seasonal cap will provide certainty, which EPA agrees is very important in the effort to help areas achieve ozone attainment. Today, EPA is finalizing an ozone season NO_X cap for States shown to contribute significantly for ozone. As is further explained in section VIII, EPA is also finalizing an ozone season trading program that States may use to achieve the required emissions reductions. This program will subsume the existing NO_X SIP Call trading program. Therefore, any State that wishes to continue including its sources in an interstate trading program run by EPA to achieve the emissions reductions required by EPA must modify its SIP to conform with this new trading program.

The EPA will automatically find that a State is continuing to meet its NO_X SIP Call obligation if it achieves all of its required CAIR emissions reductions by capping EGUs, it modifies its existing NO_X SIP Call to require its non-EGUs currently participating in the NO_X SIP Call budget trading program to conform to the requirements of the CAIR ozone season NO_X trading program with a trading budget that is the same or tighter than the budget in the currently approved SIP, and it does not modify any of its other existing NO_X SIP Call rules. If a State chooses to achieve the ozone season NO_X emissions reduction requirements of CAIR in another way, it will also be required to demonstrate that it continues to meet the requirements of the NO_X SIP Call.

Specific criteria for approval of CAIR SIP submissions as promulgated by today's action are described below. The criteria are dependent on the types of sources a State chooses to control.

2. Requirements for States Choosing To Control EGUs

a. Emissions Caps and Monitoring

As explained in the CAIR NPR (69 FR 4626), and in the CAIR SNPR (69 FR 32691), EPA proposed requiring States to apply the ''budget'' approach if they choose to control EGUs; that is, each State must cap total EGU emissions at the level that assures the appropriate amount of reductions for that State. The requirement to cap all EGUs is important because it prevents shifting of utilization (and resulting emissions) to uncapped EGUs. The EGUs are part of a highly interconnected electricity grid that makes utilization shifting likely and even common. The units are large and offer the same market product (*i.e.*, electricity), and therefore the units that are least expensive to operate are likely to be operated as much as possible. If capped and uncapped units are interconnected, the uncapped units' costs would tend to decrease relative to the capped units, which must either reduce emissions or use or buy allowances, and the uncapped units' utilization would likely increase. The cap ensures that emissions reductions

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from these interconnected sources are actually achieved rather than emissions simply shifting among sources. The caps constitute the State EGU Budgets for SO_2 and NO_X. Additionally, EPA proposed that, if States choose to control EGUs, they must require EGUs to follow part 75 monitoring, recordkeeping, and reporting requirements. Part 75 monitoring and reporting requirements have been used effectively for determining NO_X and SO_2 emissions from EGUs under the title IV Acid Rain program and the NO_X SIP Call program and in combination with emissions caps are an integral part of those programs. (Additional explanation for the need for Part 75 monitoring is given in the NPR and SNPR and is incorporated here.) Therefore, today, EPA adopts the requirements for emission caps and Part 75 monitoring for EGUs in these States.

b. Using the Model Trading Rules As

proposed, if a State chooses to allow its EGUs to participate in EPA-administered interstate NO_X and SO_2 emissions trading programs, the State must adopt EPA's model trading rules, as described elsewhere in today's preamble and in §§ 96.101–96.176 (for NO_X) and §§ 96.201–96.276 (for SO_2), set forth below. Additionally, EPA proposed that for the States for which EPA made a finding of significant contribution for both ozone and $PM_{2.5}$, participation in both the NO_X and SO_2 trading programs would be required in order to be included in the EPA-administered program. States for which the finding was for ozone only could choose to participate in only the EPA-administered NO_X trading program through adoption of the NO_X model trading rule. The EPA stated that States adopting EPA's model trading rules, modified only as specifically allowed by EPA, will meet the requirement for applying an emissions cap and requirement to use part 75 monitoring, recordkeeping, and reporting for EGUs.

Some commenters opposed EPA's proposal to require participation in both the NO_X and SO_2 trading programs because some States may want to participate in the EPA-administered trading programs for only NO_X or only SO_2. A few commenters claimed that the requirement to participate in both programs would limit State flexibility or is an ''all or nothing'' approach; other commenters objected that there was no environmental basis for such a requirement; and one commenter suggested that States not affected by CAIR but that volunteer to control emissions should be permitted to join the program for one or both pollutants. Additionally, commenters cited a need for an ozone season NO_X program.

The EPA has taken the comments into account and in today's action agrees to allow a State identified to contribute significantly for $PM_{2.5}$ (and therefore required to make annual SO_2 and NO_X reductions) to participate in the EPA-administered CAIR trading program for either SO_2 or NO_X, not necessarily both, so long as the State adopts the model rule for the applicable trading program.

In response to extensive comments relating to EPA's proposal to forego a seasonal NO_X cap because EPA demonstrated that the annual NO_X cap was sufficiently stringent, EPA is finalizing an ozone season NO_X trading program for States identified as contributing significantly for ozone. These States will be subject to an ozone season NO_X cap and an annual NO_X cap if the State is also identified as contributing significantly for $PM_{2.5}$. Therefore, today's action includes an additional model rule for an ozone season NO_X trading program (40 CFR 96, subparts AAAA through IIII). The States that may use the ozone season NO_X trading program but not the annual NO_X trading program are those States in the CAIR region identified as contributing significantly for ozone only (Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey).

As discussed in the proposal, EPA is finalizing the option for New Hampshire and Rhode Island to participate in the regional trading program through use of the CAIR ozone season NO_X model rule because sources in these States have made investments in NO_X controls in the past based on the existence of a regional ozone season NO_X trading program. Additionally, the States' combined projected 2010 and 2015 NO_X emissions are less than one-half of one percent of the total CAIR regional NO_X cap and therefore would not create a significant increase in the CAIR cap. All comments received were supportive of this approach and EPA is finalizing it today.

None of these States (Arkansas, Connecticut, Delaware, Massachusetts, New Hampshire, New Jersey, or Rhode Island) has the option to participate in the EPA-administered CAIR SO_2 trading program nor the annual CAIR NO_X trading program because there are no $PM_{2.5}$-related emissions reductions required under today's action in those States. (Of course, sources in these States will still be subject to the Acid Rain SO_2 cap and trade program.) Likewise, Texas, Minnesota and Georgia may not participate in the ozone season NO_X program, because they have not been shown to contribute significantly to the regional ozone problem. They are, however, required to make annual NO_X and SO_2 reductions and may choose to participate in the annual NO_X and annual SO_2 trading program to meet their CAIR obligations.

Except for the special cases of Rhode Island and New Hampshire, other States outside of the CAIR region may not participate in the CAIR trading programs for either pollutant, because they were not shown to contribute significantly to $PM_{2.5}$ or ozone nonattainment in the CAIR region. Allowing States outside of the CAIR region to participate would generally create an opportunity—through net sales of allowances from the non-CAIR States to CAIR States—for emission increases in States that have been shown to contribute significantly to nonattainment in the CAIR region.[108]

A State may not participate in the EPA-administered trading programs if they choose to get a portion of CAIR reductions from non-EGUs. (This is also discussed in Section VIII.) The EPA maintains that requiring certain consistencies among States in the regionwide trading programs that EPA has offered to run does not unfairly limit States' flexibility to choose an approach for achieving CAIR mandated reductions that is best suited for a particular State's unique circumstances. States are free to achieve the reductions through whatever alternative mechanisms the States wish to design; for example, a group of States could cooperatively implement their own multi-State trading programs that EPA would not administer.

c. Using a Mechanism Other Than the Model Trading Rules

If States choose to control EGUs through a mechanism other than the EPA-administered NO_X and SO_2 emissions trading programs, then the States (i) must still impose an emissions cap on total EGU emissions and require part 75 monitoring, recordkeeping, and reporting requirements on all EGUs, and (ii) must use the same definition of EGU as EPA uses in its model trading rules, i.e., the sources described as ''CAIR units'' in § 96.102, § 96.202, and § 96.302. A few commenters expressed concern that these requirements limit States' discretion in designing control measures to meet the CAIR requirements, but failed to offer any

[108] Title IV allowances can however be traded freely across the boundary of the CAIR region without any significant, negative environmental consequence. The potential negative consequences have been addressed through other requirements discussed below, like the retirement of excess title IV allowances.

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reason why the requirements would be impracticable or ineffective. The EPA believes that the requirements are necessary for a number of reasons. The requirements to cap all EGUs and to use the same definition of EGU are important because they prevent shifting of utilization (and resulting emissions) from capped to uncapped sources. In this case, not requiring a cap on total EGU emissions in these States is likely to result in increased utilization and consequently increased emissions in these States. The requirement to use part 75 monitoring ensures the accuracy of monitored data and consistency of reporting among sources (and thus the certainty that emissions reductions actually occurred) across all States. Furthermore, most EGUs are currently monitoring and reporting using part 75 so it does not impose an additional requirement. Therefore, EPA is finalizing the proposed approach.

If a State chooses to design its own intrastate or interstate NO_X or SO_2 emissions trading programs, the State must, in addition to meeting the requirements of the rules finalized in today's action, consider EPA's guidance, ''Improving Air Quality with Economic Incentive Programs,'' January, 2001 (EPA–452/R–01–001) (available on EPA's Web site at: *http://www.epa.gov/ttn/ecas/incentiv.html*). The State's programs are subject to EPA approval. The EPA will not administer a State-designed trading program. Additionally, it should be noted that allowances from any alternate trading program may not be used in the EPA-administered trading programs.

d. Retirement of Excess Title IV Allowances

The CAIR NPR proposed requirements on SIPs relating to the effects of title IV SO_2 allowance allocations for 2010 and beyond that are in excess of the State's CAIR EGU SO_2 emissions budget. The requirements were intended to ensure that the excess is not used in a manner that would lead to a significant increase in supply of title IV allowances, the collapse of the price of title IV allowances, the disruption of operation of the title IV allowance market and the title IV SO_2 cap and trade system, and the potential for increased emissions in all States prior to 2010 and in non-CAIR States in 2010 and later. These negative impacts on the title IV allowance market and on air quality, which are discussed in detail in section IX.B. below, would undermine the efficacy of the title IV program and could erode confidence in cap and trade programs in general. To avoid these impacts, EPA proposed to require retirement of the excess title IV allowances through a retirement ratio mechanism.

The EPA proposed, as a mechanism for removing these additional allowances and meeting the 50 percent reduction required under phase I (2010–2014), that each affected EGU had to hold, and EPA would retire, two vintage 2010–2014 allowances for every ton of SO_2 that the unit emits. Further, EPA proposed that, for phase II (which begins in 2015) when a 65 percent reduction is required, each affected EGU had to hold, and EPA would retire, three vintage 2015 and beyond allowances for every ton of SO_2 that the unit emits. This 3-to-1 ratio would result in slightly more reductions than EPA has determined were necessary to eliminate the significant contribution by an upwind State.

In the CAIR SNPR, EPA proposed two alternatives for addressing the issue of the additional allowances. Under the first alternative, affected EGUs had to hold, and EPA would retire, vintage 2015 and beyond allowances at a rate of 2.86-to-1 rather than 3-to-1, which would result in exactly the amount of reductions EPA has determined are necessary to eliminate a State's significant contribution.

Alternatively, also in the CAIR SNPR, EPA proposed requiring the retirement of 2015 and beyond vintage allowances at a 3-to-1 ratio and permitting States to convert the additional reductions into allowances in their rules. The EPA also suggested that some States may want to use these reserved allowances to create an incentive for additional local emissions reductions that will be needed to bring all areas into attainment with the $PM_{2.5}$ NAAQS.

As part of today's final CAIR rulemaking, EPA is finalizing a ratio of 2.86-to-one. The ratio ultimately represents a reduction of 65 percent from the final title IV cap level, which has been found to be highly cost-effective. For a detailed discussion regarding EPA's determination of highly cost-effective, please refer to Section IV of the final CAIR preamble. As discussed earlier, EPA must employ a uniform ratio across sources to ensure consistency and the same cost-effectiveness level across sources. Therefore, EPA will use a Phase II ratio of 2.86-to-1 for all States affected by CAIR who choose to participate in the trading program.

Today, EPA is finalizing the general requirement that all SIPs must include a mechanism to ensure that excess SO_2 allowances are retired. Furthermore, for States that participate in the EPA-administered cap and trade program, EPA is finalizing a specific mechanism that States must use.

i. States Participating in the EPA-Administered SO_2 Trading Program

If a State chooses to participate in the EPA-administered trading program, the State's excess title IV allowance retirement mechanism must follow the provisions of the SO_2 model trading rule that requires that vintage 2010 through 2014 title IV allowances be retired at a ratio of two allowances for every ton of emissions and that vintage 2015 and beyond title IV allowances be retired at a ratio of 2.86 allowances for every ton of emissions. Pre-2010 vintage allowances would be retired at a ratio of one allowance for every ton of emissions. (See discussion of the model SO_2 cap and trade rule in section VIII of today's preamble.) States using the model SO_2 cap and trade rule satisfy the requirement for retirement of excess title IV allowances.

ii. States Not Participating in the EPA-Administered SO_2 Trading Program

In the CAIR NPR, EPA stated that if a State does not choose to participate in the EPA-administered trading programs but controls only EGUs, the State may choose the specific method to retire allowances in excess of its budget. The EPA considered alternative ways for retiring these excess allowances and, as stated in the CAIR SNPR, believed that the use by different States of different means to address this concern could undermine the regionwide emissions reduction goals of the CAIR rulemaking. The EPA further described its concerns in section II of the preamble to the CAIR SNPR. (*See* 69 FR 32686–32688.) Because of these concerns, in the CAIR SNPR, EPA withdrew the CAIR NPR proposal on this point and re-proposed that all States use a 2-for-1 retirement ratio for vintage 2010 through 2014 allowances and a 2.86-for-1 or a 3-for-1 retirement ratio for vintage 2015 and beyond allowances to address concerns about title IV allowances that exceed State budgets. The EGUs would have a total emissions cap enforced by the State.

The SNPR described that for sources affected by both title IV and CAIR, allowance deductions and associated compliance determinations would be sequential. That is, title IV compliance would be determined and then CAIR compliance would be determined. So, in 2010–2014, after surrendering one vintage 2010 through 2014 allowance for each ton of emissions for title IV compliance, the source would then surrender one additional allowance (for a total of two allowances for each ton

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which meets the CAIR requirement). Similarly, in 2015 and beyond, after surrendering one vintage 2015 and beyond allowance for each ton of emissions for title IV compliance, the source would surrender 1.86 or 2 additional allowances and therefore meet the CAIR requirement. Commenters argued that in States where EGUs are not trading under CAIR that the excess title IV allowances could be removed in a variety of ways and that EPA did not need to require each State do this the same way, only that each State ensure that they are removed.

Today, EPA adopts the following requirement: If a State does not choose to participate in the EPA-administered trading programs but controls only EGUs, the State must include in its SIP a mechanism for retiring the excess title IV allowances (i.e., the difference between total allowance allocations in the State and the State EGU SO_2 budget). To meet this requirement, the State may use the above-described retirement mechanism or may develop a different mechanism that will achieve the required retirement of excess allowances.

3. Requirements for States Choosing to Control Sources Other Than EGUs

a. Overview of Requirements

As noted in both the CAIR NPR and the CAIR SNPR, if a State chooses to require emissions reductions from non-EGUs, the State must adopt and submit SIP revisions and supporting documentation designed to quantify the amount of reductions from the non-EGU sources and to assure that the controls will achieve that amount. Although EPA did not propose in the CAIR NPR that States be required to impose an emissions cap on those sources, but instead solicited comment on the issue, EPA proposed in the CAIR SNPR that States be required to impose an emissions cap in certain cases on non-EGU sources. (See discussion in VII.A.1 of today's preamble.)

If a State chooses to obtain some, but not all, of its required reductions for SO_2 or NO_X emissions from non-EGUs, it would still be required to set an EGU budget for SO_2 or NO_X respectively, but it would set such a budget at some level higher than shown in Tables V–1, V–2, or V–4 in today's preamble, thus allowing more emissions from EGUs. The difference between the amount of a State's SO_2 budget in Table V–1 and a State's selected higher EGU SO_2 budget would be the amount of SO_2 emissions reductions the State demonstrates it will achieve from non-EGU sources. By the same token, the difference between the amount of a State's annual NO_X budget in Table V–2 and a State's selected higher annual EGU NO_X budget would be the amount of annual NO_X emissions reductions the State demonstrates it will achieve from non-EGU sources.[109] Further, the difference between the amount of a State's seasonal NO_X budget in Table V–4 and a State's selected higher ozone season EGU NO_X budget would be the amount of ozone season NO_X emissions reductions the State demonstrates it will achieve from non-EGU sources.

Special Concerns About SO_2 Allowances

In the case where a State requires a portion of its SO_2 emissions reductions from non-EGU sources and a portion from EGUs, there remains a concern about the impact of excess title IV allowances above a State's EGU cap, particularly on the operation of the title IV SO_2 cap and trade program. Consequently, today, we are adopting the requirement that these States include a mechanism for retirement of the allowances in excess of the State's SO_2 budget.

Like a State choosing to control only EGUs but not to participate in the trading program, a State that chooses to control non-EGUs and EGUs must adopt a mechanism for retiring surplus title IV allowances. The number of title IV allowances that must be retired is equal to the difference between the number of title IV allowances allocated to EGUs in that State and the SO_2 budget the State sets for EGUs under this rule. If the State uses a retirement mechanism (as discussed in VII.A.2.d.) in which a source surrendering allowances under the title IV SO_2 cap and trade program surrenders more allowances than otherwise required under title IV, the total number of allowances surrendered per ton of emissions in this case will be less than 2 to 1 in Phase 1 and less than 2.86 to 1 in Phase 2. This is because the non-EGUs will control to achieve a portion of the CAIR SO_2 reduction required, and so there will be a smaller surplus of title IV allowances than if all the required reductions were achieved by EGUs. The appropriate retirement factor will equal two times the State's SO_2 budget in Phase I or 2.86 times the State's SO_2 budget in Phase II as noted in Table V–1 of the budget section, divided by the State's selected higher EGU SO_2 budget (taking into account non-EGU reductions). The factor could then be used as the EGU retirement ratio for compliance purposes in a scenario where a State has decided to control SO_2 emissions from EGUs through a mechanism other than the EPA-administered trading program.

A simplified example can help illustrate this. Let us assume a State's sources were allocated a total of 200 allowances under title IV. Under CAIR, in Phase I, the State's reduction requirement would thus be 100 tons. Suppose this State decided that 25 tons would be reduced by non-EGUs and the remaining 75 tons would be reduced by the EGUs. (The State's budget for EGUS would increase to 125 tons.) The State would also need to retire 75 excess title IV allowances. This could be accomplished by requiring each Acid Rain source to surrender a total of 1.6 vintage 2010 through 2014 allowances (200 allowances allocated in the State/ 125 tons in State EGU budget) per ton of SO_2 emissions. The allowances surrendered would satisfy the Acid Rain Program requirement of surrendering one allowance per ton of emissions, as well as achieving the additional retirement requirement under CAIR since 200 allowances would be used for EGUs to emit the EGU budget of 125 tons of SO_2. (Pre-2010 allowances continue to be available for use on a one-allowance-per-ton-of-emissions basis here as in other situations.)

This is consistent with EPA's overall approach. If this same State decided to get all reductions (i.e., 100 tons) from EGUs, the State would require EGUs to retire 100 additional allowances by surrendering a total of 2 vintage 2010 through 2014 allowances (200 allowances allocated in the State/100 tons in State EGU budget) per ton of SO_2 emissions.

The demonstration of emissions reductions from non-EGUs is a critical requirement of the SIP revision due from a State that chooses to control non-EGUs. The State must take into account the amount of emissions attributable to the source category in both (i) the base case, in the implementation years 2010 and 2015, i.e., without assuming any SIP-required reductions under the CAIR from non-EGUs; and (ii) in the control case, in the implementation years 2010 and 2015, i.e., assuming SIP-required reductions under the CAIR from non-EGUs. We proposed an alternative methodology for calculating the base case for certain large non-EGU sources, as described below, but generally the difference between emissions in the base case and emissions in the control

[109] In the CAIR SNPR, EPA mistakenly cited the EGU budget numbers from Tables VI–9 and VI–10 in the CAIR NPR (69 FR 4619–20) when it should have cited Tables II–1 and II–2 in the CAIR SNPR. The EPA used the correct numbers, however, in the proposed regulatory text in the CAIR SNPR (69 FR 32729–30 and 69 FR 32733–34 (§§ 51.123(e)(2) and 51.124(e)(2)).

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case equals the amount of emissions reductions that can be claimed from application of the controls on non-EGUs. (See discussion later in this section for criteria applicable to development of the baseline and projected control emissions inventories.)

States that meet the lesser of their CAIR ozone season NO_X budget or NO_X SIP Call EGU trading budget using the CAIR ozone season NO_X trading program also satisfy their NO_X SIP Call requirements for EGUs. States may also choose to include all of their NO_X SIP Call non-EGUs in the CAIR ozone season NO_X program at their NO_X SIP Call levels (i.e., the non-EGU trading budget remains the same).

To the extent EPA allows through the Regional Haze Rule and a State then chooses to use EPA analysis to show that CAIR reductions from EGUs meet BART requirements, States that achieve a portion of their CAIR reductions from sources other than EGUs and wanting to show that even with those reductions the EGUs will meet BART requirements must make a supplemental demonstration that BART requirements are satisfied.

b. Eligibility of Non-EGU Reductions

In the CAIR SNPR, EPA proposed that, in evaluating whether emissions reductions from non-EGUs would count towards the emissions reductions required under the CAIR, States may only include reductions attributable to measures that are not otherwise required under the CAA. Specifically, EPA proposed that States must exclude non-EGU reductions attributable to measures otherwise required by the CAA, including: (1) Measures required by rules already in place at the date of promulgation of today's final rule, such as adopted State rules, SIP revisions approved by EPA, and settlement agreements; (2) measures adopted and implemented by EPA (or other Federal agencies) such as emissions reductions required pursuant to the Federal Motor Vehicle Control Program for mobile sources (vehicles or engines) or mobile source fuels, or pursuant to the requirements for National Emissions Standards for Hazardous Air Pollutants; and (3) specific measures which are mandated under the CAA (which may have been further defined by EPA rulemaking) based on the classification of an area which has been designated nonattainment for a NAAQS, such as vehicle inspection and maintenance programs.

In discussing this proposal, EPA noted that States required to make CAIR SIP submittals may also be required to make separate SIP submittals to meet other requirements applicable to non-EGUs, *e.g.*, nonattainment SIPs required for areas designated nonattainment under the $PM_{2.5}$ or 8-hour ozone NAAQS or regional haze SIPs. The EPA noted it is likely that CAIR SIP submittals will be due before or at the same time as some of these other SIP submittals. We therefore proposed that States relying on reductions from controls on non-EGUs must commit in the CAIR SIP revisions to replace the emissions reductions attributable to any CAIR SIP measure if that measure is subsequently determined to be required to meet any other SIP requirement.

Some commenters objected to the proposed exclusion of credit for measures which are mandated under the CAA based on the classification of an area which has been designated nonattainment for a NAAQS, as well as to the proposed requirement that such measures must be replaced if they are later determined to be required in meeting separate SIP requirements. These commenters reasoned that such a requirement would not be applied to EGUs and would impose unnecessary and costly burdens on non-EGUs, thus creating an incentive for States to avoid controlling non-EGUs and to impose all CAIR reduction requirements on EGUs. One commenter further objected that, as long as a measure was not included in the base case EPA used to determine a State's contribution to other States' nonattainment under CAA section 110(a)(2)(D), there is no justification for excluding CAIR credit for such measure, and that EPA's proposed exclusion of credit for any measure ''otherwise required by the CAA'' is inconsistent with the NO_X SIP Call.

In response to these comments, EPA agrees that it is not appropriate to apply this proposed restriction inconsistently to EGUs and non-EGUs. Thus, EPA is adopting a modified form of the proposed criteria for the eligibility of non-EGU emissions reductions, eliminating the requirement that States must exclude non-EGU reductions attributable to measures otherwise required by the CAA based on the classification of an area which has been designated nonattainment for a NAAQS. Consequently, the final rule allows credit for measures that a State later adopts in response to requirements which result from an area's nonattainment classification, such as reasonably available control technology (RACT). With this change, all emissions reductions are eligible for credit in meeting CAIR except: (1) Measures adopted or implemented by the State as of the date of promulgation of today's final rule, such as adopted State rules, SIP revisions approved by EPA, and settlement agreements; and (2) measures adopted or implemented by the Federal government (*e.g.*, EPA or other Federal agencies) as of the date of submission of the SIP revision by the State to EPA, such as emissions reductions required pursuant to the Federal Motor Vehicle Control Program for mobile sources (vehicles or engines) or mobile source fuels, or pursuant to the requirements for National Emissions Standards for Hazardous Air Pollutants.

This exclusion of credit is consistent with EPA's approach in the NO_X SIP Call, although a direct comparison of the creditability requirements in the CAIR and in the NO_X SIP Call is not possible due to the timing and context in which both rules were developed. The NO_X SIP Call used statewide budgets for all sources as an accounting tool to determine the adequacy of a strategy, while the CAIR takes a different approach in which baseline emission inventories for non-EGU sectors will, if needed, be developed later. The NO_X SIP Call did, as does the CAIR, restrict States from taking credit for any Federal measures adopted after promulgation of the rule (63 FR 57427–28). It also did not allow credit for already adopted measures, but the timing of the NO_X SIP Call was such that nonattainment planning measures would have already likely been adopted as the SIP deadlines for adoption of such measures had passed. In today's action, nonattainment planning measures adopted after the promulgation of today's rule will be allowed credit under CAIR.

In order to take credit for CAIR reductions from non-EGUs, the reductions must be beyond what is required under the NO_X SIP Call. That is, a reduction must be in the non-ozone season or it must be beyond what is expected in the ozone season. Non-ozone season reductions must also be beyond what is in the base case, particularly for units that have low NO_X burners and certain SCRs (*e.g.*, ones required to be run annually). The reductions must be in addition to those already expected. If ozone season reductions are considered, the non-EGU NO_X SIP Call trading budget must be adjusted by the increment of CAIR reductions beyond the levels in the NO_X SIP Call. This removes the corresponding allowances from the market and ensures that the emissions do not shift to other sources.

After evaluating the eligibility of non-EGU reductions in accordance with the requirements discussed here, States must exclude credit for ineligible

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measures by (i) including such measures in both the baseline and controlled emissions inventory cases, if they have already been adopted; or (ii) excluding them from both the base and control emissions inventory cases if they have not yet been adopted. (*See* discussion later in this section regarding development of emissions inventories and demonstration of non-EGU reductions.)

c. Emissions Controls and Monitoring

As noted in section VII.A.1., we modified the ''hybrid'' approach described in the CAIR NPR as it applies to certain non-EGUs, and adopt today the approach described in the CAIR SNPR. Specifically, for States that choose to impose controls on large industrial boilers and turbines, *i.e.*, those whose maximum design heat input is greater than 250 mmBtu/hr, to meet part or all of their emissions reductions requirements under the CAIR, State rules must include an emissions cap on all such sources in their State. Additionally, in this situation, States must require those large industrial boilers and turbines to meet part 75 requirements for monitoring and reporting emissions as well as recordkeeping. This ensures consistency in measurement and certainty of reductions and has been proven technologically and economically feasible in other programs.

If a State chooses to control non-EGUs other than large industrial boilers and turbines to obtain the required emissions reductions, the State must either (i) impose the same requirements, *i.e.*, an emissions cap on total emissions from non-EGUs in the source category in the State and part 75 monitoring, reporting and recordkeeping requirements; or (ii) demonstrate why such requirements are not practicable. In the latter case, the State must adopt appropriate alternative requirements to ensure that emissions reductions are being achieved using methods that quantify those emissions reductions, to the extent practicable, with the same degree of assurance that reductions are being quantified for EGUs and non-EGU boilers and turbines using part 75 monitoring. This is to ensure that, regardless of how a State chooses to meet the CAIR emissions reduction requirements, all reductions made by States to comply with the CAIR have the same, high level of certainty as that achieved through the cap and trade approach. Further, if a State adopts alternative requirements that do not apply to all non-EGUs in a particular source category (defined to include all sources where any aspect of production of one or more such sources is reasonably interchangeable with that of one or more other such sources), the State must demonstrate that it has analyzed the potential for shifts in production from the regulated sources to unregulated or less stringently regulated sources in the same State as well as in other States and that the State is not including reductions attributable to sources that may shift emissions to such unregulated or less regulated sources.

d. Emissions Inventories and Demonstrating Reductions

To quantify emissions reductions attributable to controls on non-EGUs, the States must submit both baseline and projected control emissions inventories for the applicable implementation years. We have issued many guidance documents and tools for preparing such emissions inventories, some of which apply to specific sectors States may choose to control.[110] While much of that guidance is applicable to today's rulemaking, there are some key differences between quantification of emissions reduction requirements under a SIP designed to help achieve attainment with a NAAQS and emissions reduction requirements under a SIP designed to reduce emissions that contribute significantly to a downwind State's nonattainment problem or interfere with maintenance in a downwind State. Because States are taking actions as a result of their impact on other States, and because the impacted States have no authority to reduce emissions from other States, the emissions reduction estimates become even more important. (For a complete discussion, see 69 FR 32693; June 10, 2004.)

Specifically, when we review CAIR SIPs for approvability, we intend to review closely the emissions inventory projections for non-EGUs to evaluate whether emissions reduction estimates are correct. We intend to review the accuracy of baseline historical emissions for the subject sources, assumptions regarding activity and emissions growth between the baseline year and 2010 [111] and 2015, and assumptions about the effectiveness of control measures.

Before describing the specific steps involved in this quantification process, EPA notes that a few commenters objected to the proposed requirements as arbitrary restrictions intended to discourage States' discretion in imposing control measures on non-EGUs since these requirements would use what the commenters describe as extremely conservative emissions baseline and emissions reduction estimates. No commenter refuted EPA's explanation, noted above, of the need for stringent requirements to ensure greater accuracy of emission inventories and greater certainty of reduction estimates used in SIPs addressing transported pollutants. The EPA maintains that the need for more accurate inventories and more certain reduction estimates justifies the requirements discussed below. Further, no commenter provided an alternate method of addressing EPA's concerns about the development of such inventories and reduction estimates. Thus, EPA is finalizing its proposed approach.

i. Historical Baseline

To quantify non-EGU reductions, as the first step, a historical baseline must be established for emissions of SO_2 or NO_X from the non-EGU source(s) in a recent year. The historical baseline inventory should represent actual emissions from the sources prior to the application of the controls. We expect that States will choose a representative year (or average of several years) during 2002–2005 for this purpose.

The requirements for estimating the historical baseline inventory that follow reflect EPA's view that, when States assign emissions reductions to non-EGU sources, achievement of those reductions should carry a high degree of certainty, just as EGU reductions can be quantified with a high degree of certainty in accordance with the applicable part 75 monitoring requirements. Because the non-EGU emissions reductions are estimated by subtracting controlled emissions from a projected baseline, if the historical baseline overestimates actual emissions, the estimated reductions could be higher than the actual reductions achieved.

For non-EGU sources that are subject to part 75 monitoring requirements, historical baselines must be derived from actual emissions obtained from part 75 monitored data. For non-EGU sources that do not have part 75 monitoring data, historical baselines must be established that estimate actual

[110] The many EPA guidance documents and tools for preparing emission inventory estimates for SO_2 and NO_X are available at the following Web sites: *http://www.epa.gov/ttn/chief/net/general.html*, *http://www.epa.gov/ttn/chief/eiip/techreport/*, *http://www.epa.gov/ttn/chief/publications.html#general*, *http://www.epa.gov/ttn/chief/software/index.html*, and *http://www.epa.gov/ttn/chief/efinformation.html*.

[111] The 2010 modeling date is relevant for both SO_2 and NO_X even though NO_X requirements begin in 2009. See Section IV for discussion.

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emissions in a way that matches or approaches as closely as possible the certainty provided by the part 75 measured data for EGUs. For these sources, States must estimate historical baseline emissions using source-specific or category-specific data and assumptions that ensure a source's or source category's actual emissions are not overestimated.

To determine the baseline for sources that do not have part 75 measured data, States must use emission factors that ensure that emissions are not overestimated (*e.g.*, emission factors at the low end of a range when EPA guidance presents a range) or the State must provide additional information that shows with reasonable confidence that another value is more appropriate for estimating actual emissions. Other monitoring or stack testing data can be considered, but care must be taken not to overestimate baselines. If a production or utilization factor is part of the historical baseline emissions calculation, a factor that ensures that emissions are not overestimated must be used, or additional data must be provided. Similarly, if a control or rule effectiveness factor enters into the estimate of historical baseline emissions, such a factor must be realistic and supported by facts or analysis. For these factors, a high value (closer to 100 percent control and effectiveness) ensures that emissions are not overestimated.

ii. Projections of 2010 and 2015 Baselines

The second step in quantifying SO_2 or NO_X emissions reductions for non-EGUs is to use the historical baseline emissions and project emissions that would be expected in 2010 and 2015 without the CAIR. This step results in the 2010 and 2015 baseline emissions estimates.

The EPA proposed and requested comment on two procedures for estimating the future baselines: one relies on projections based on a number of estimated parameters; the second uses the lower of this projection and actual historical emissions. Today, EPA finalizes the second approach for determining 2010 and 2015 emissions baselines.

To estimate future emissions, States must use state-of-the-art methods for projecting the source or source category's economic output. Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are themselves inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the most recent Annual Energy Outlook published by the U.S. Department of Energy, then adjustments must be made to correct the inconsistency, or the SIP must demonstrate how the official planning assumptions are more accurate. If the State expects changes in production method, materials, fuels, or efficiency to occur between the baseline year and 2010 or 2015, the State must account for these changes in the projected 2010 and 2015 baseline emissions. For example, if a source has publicly announced a change or applied for a permit for a change, it should be reflected in the projections. The projection must also reflect any adopted regulations that are ineligible control measures and that will affect source emissions.

As stated above, EPA is requiring States to use the lower of historical baseline emissions or projected 2010 or 2015 emissions, as applicable, for a source category. This is because changes in production method, materials, fuels, or efficiency often play a key role in changes in emissions. Because of factors such as these, emissions can often stay the same or even decrease as productivity within a sector increases. These factors that contribute to emission decreases can be very difficult to quantify. Underestimating the impact of these types of factors can very easily result in a projection for increased emissions within a sector, when a correct estimate will result in a projection for decreased emissions within the sector. A few commenters opposed this methodology as arbitrary but failed to explain why EPA's concerns, as described above, are not valid. Commenters also failed to propose other methodologies for addressing these concerns. Thus, EPA is finalizing the use of this second methodology.

iii. Controlled Emissions Estimates for 2010 and 2015

The third step is to develop the 2010 and 2015 controlled emissions estimates by assuming the same changes in economic output and other factors listed above but adding the effects of the new controls adopted for the purpose of meeting the CAIR. The controls may take the form of regulatory requirements, *e.g.*, emissions caps, emission rate limits, technology requirements, or work practice requirements. The State's estimate of the effect of the control regulations must be realistic in light of the specific provisions for monitoring, reporting, and enforcement and experience with similar regulatory approaches.

In addition, the State's analysis must examine the possibility that the controls may cause production and emissions to shift to unregulated or less stringently regulated sources in the same State or another State. If all sources of a source category (defined to include all sources where any aspect of production is reasonably interchangeable) within the State are regulated with the same stringency and compliance assurance provisions, the analysis of production and emissions shifts need only consider the possibility of shifts to other States. If only a portion of a source category within a State is regulated, the analysis must also include any in-State shifting. In estimating controlled emissions in 2010 and 2015, assumptions regarding control measures that are not eligible for CAIR reduction credit must be the same as in the 2010 and 2015 baseline estimates. For example, a State may not take credit for reductions in the sulfur content of nonroad diesel fuel that are required under the recent Federal nonroad fuel rule (69 FR 38958; June 29, 2004). By including the effect of this Federal rule in both the baseline and controlled emissions estimates for 2010 and 2015, the State will appropriately exclude this ineligible reduction when it subtracts the controlled emissions estimates from the baseline emissions estimates.

The method that we are adopting today specifies the 2010 and 2015 emissions reductions which can be counted toward satisfying the CAIR. The method requires the use of the historical baseline or the baseline emission estimates, whichever is lower. That is, the reduction is calculated as follows: (i) For 2010, the difference between the lower of historical baseline or 2010 baseline emissions estimates and the 2010 controlled emissions estimates, minus any emissions that may shift to other sources rather than be eliminated; and (ii) for 2015, the difference between the lower of historical baseline or 2015 baseline emissions estimates and the 2015 controlled emissions estimates, minus any emissions that may shift to other sources rather than be eliminated.

4. Controls on Non-EGUs Only

Although we stated that we believe it is unlikely States may choose to control only non-EGUs, we proposed in the CAIR SNPR provisions for determining

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the specified emissions reductions that must be obtained if States pursue this alternative, and we adopt those provisions today. The reason we think it is unlikely is based on States' emissions profiles. Most SO_2 emissions are from EGUs and therefore it is unlikely that a State can achieve the required emissions reductions without regulating EGUs to some degree. In addition, SO_2 emissions reductions from EGUs are highly cost effective. States that choose this path must ensure that the amount of non-EGU reductions is equivalent to all of the emissions reductions that would have been required from EGUs had the State chosen to assign all the emissions reductions to EGUs. For SO_2 emissions, this amount in 2010 would be 50 percent of a State's title IV SO_2 allocations for all units in the State and, for 2015, 65 percent of such allocations. For NO_X emissions, this amount would be the difference between a State's EGU budget for NO_X under the CAIR and its NO_X baseline EGU emissions inventory as projected in the Integrated Planning Model (IPM) for 2010 and 2015, respectively.[112]

In addition, the same requirements described elsewhere in this part of today's preamble regarding the eligibility of non-EGU reductions, emissions control and monitoring, emissions inventories and demonstration of reductions, will apply to the situation where a State chooses to control only non-EGUs.

5. Use of Banked Allowances and the Compliance Supplement Pool

In the CAIR NPR, EPA stated that States may allow EGUs to demonstrate compliance with the State EGU SO_2 budget by using title IV allowances (i) that were banked, or (ii) that were obtained in the current year from sources in other States (69 FR 4627). The EPA adopts this provision in today's action. The EPA adopts a similar provision for the use of banked NO_X SIP Call allowances (pre-2009) to demonstrate compliance with the State EGU ozone season NO_X budget. See also the CAIR NPR (69 FR 4633). Therefore, State rules may allow the use of pre-2010 title IV and pre-2009 NO_X SIP Call allowances banked in the title IV and NO_X SIP Call trading programs for compliance in the CAIR. States participating in the EPA-administered CAIR trading programs must allow the use of these pre-2010 title IV allowances or pre-2009 NO_X SIP Call allowances in accordance with EPA's model trading rules.

Additionally, States with annual NO_X reduction requirements may use compliance supplement pool (CSP) allowances as described in sections V and VIII. Distribution of the CSP is essentially the same as the process used in the NO_X SIP Call, through one or both of two mechanisms. States may distribute CSP allowances on a pro-rata basis to sources that implement NO_X control measures resulting in reductions in 2007 or 2008 that are beyond what is required by any applicable State or Federal emissions limitation (early reductions). The second CSP distribution mechanism that a State can use is to issue CSP allowances based on the demonstration of a need for an extension of the 2009 deadline for implementing emission controls. The demonstration must show unacceptable risk either to a source's own operation or its associated industry—for EGUs, power supply reliability, for non-EGUs risk comparable to that described for the electricity industry. See also 63 FR 57356 for further discussion of these points.

Pre-2010 title IV SO_2 allowances, pre-2009 NO_X SIP Call allowances and CAIR annual NO_X CSP allowances can all be counted toward a States efforts to achieve its CAIR reduction obligations regardless of whether the CAIR trading programs are used or not.

B. State Implementation Plan Schedules

1. State Implementation Plan Submission Schedule

In the NPR, we proposed to require States to submit SIPs to address interstate transport in accordance with the provisions of this rule approximately 18 months from the date of this final rule (69 FR 4624). After careful consideration of the comments we received concerning this issue, we have concluded that States should submit SIPs to satisfy this final rule as expeditiously as possible, but no later than 18 months from the date of today's action. Under this schedule, upwind States' transport SIPs to meet CAA section 110(a)(2)(D) will be due before the downwind States' $PM_{2.5}$ and 8-hour ozone nonattainment area SIPs under CAA section 172(b). We expect that the downwind States' 8-hour ozone nonattainment area SIPs will be due by June 15, 2007, and their $PM_{2.5}$ nonattainment SIPs will be due by April 5, 2008.[113]

We believe that this sequence for SIP submissions to address upwind interstate transport and downwind nonattainment areas is consistent both with the applicable provisions of the CAA and with sound policy objectives. The CAA provides for this sequence of submissions in section 110(a)(1) and (a)(2), which provide that the submittal period for SIPs required by section 110(a)(2)(D) runs from the earlier date of the NAAQS revision, and in section 172(b), which provides that the submittal period for the nonattainment area SIPs runs from the later date of designation. Clean Air Act section 110(a)(1) requires each State to submit a SIP to EPA "within 3 years * * * after the promulgation of a [NAAQS] (or any revision thereof)." Section 110(a)(2) makes clear that this SIP must include, among other things, provisions to address the requirements of section 110(a)(2)(D). We read these provisions together to require that each upwind State must submit, within 3 years of a new or revised NAAQS, SIPs that address the section 110(a)(2)(D) requirement. By contrast, the schedule provided in section 172(b) is only applicable to the nonattainment area SIP requirements.

Section 110(a) imposes the obligation upon States to make a submission, but the contents of that submission may vary depending on the facts and circumstances. In particular, the data and analytical tools available at the time the section 110(a)(2)(D) SIP is developed and submitted to EPA necessarily affect the content of the submission. Where, as here, the data and analytical tools to identify a significant contribution from upwind States to nonattainment areas in downwind States are available, the State's SIP submission must address the existence of the contribution and the emission reductions necessary to eliminate the significant contribution. In other circumstances, however, the tools and information may not be available. In such circumstances, the section 110(a)(2)(D) SIP submission should indicate that the necessary information is not available at the time the submission is made or that, based on the information available, the State believes that no significant contribution to downwind nonattainment exists. EPA can always act at a later time after the initial section 110(a)(2)(D) submissions to issue a SIP call under section 110(k)(5) to States to revise their SIPs to provide for additional emission controls to satisfy the section 110(a)(2)(D) obligations if such action were

[112] See "Technical Support Document for the Clean Air Interstate Rule Notice of Final Rulemaking; Regional and State SO_2 and NO_X Emissions Budgets" for tables containing information to calculate these amounts for both SO_2 and NO_X.

[113] By statute, the date for submission of nonattainment area SIPs is to be no later than 3 years from the date of nonattainment designation. Section 172(b).

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warranted based upon subsequently-available data and analyses. This is precisely the circumstance that was presented at the time of the NO_X SIP Call in 1998 when EPA issued a section 110(k)(5) SIP call to states regarding their section 110(a)(2)(D) obligations on the basis of new information that was developed years after the States' SIPs had been previously approved as satisfying section 110(a)(2)(D) without providing for additional controls since the information available at the earlier point in time did not indicate the need for such additional controls.

Not only is this sequencing consistent with the CAA, it is consistent with sound policy considerations. The upwind reductions required by today's action will facilitate attainment planning by the States affected by transport downwind. Rather than being ''premature'' as some commenters suggested, EPA's understanding of the data and models leads the Agency to believe that requiring the States to address the upwind transport contribution to downwind nonattainment earlier in the process as a first step is a reasonable approach and is fully consistent with the statutory structure. This approach will allow downwind States to develop SIPs that address their share of emissions with knowledge of what measures upwind States will have adopted. In addition, most of the downwind States that will benefit by today's rulemaking are themselves significant contributors to violations of the standards further downwind and, thus, are subject to the same requirements as the States further upwind. The reductions these downwind States must implement due to their additional role as upwind States will help reduce their own $PM_{2.5}$ and 8-hour ozone problems on the same schedule as emissions reductions for the upwind States. We believe that providing 18 months from the date of today's action for States to submit the transport SIPs required by this rule is appropriate and reasonable, for the reasons discussed more fully below.

a. The EPA's Authority To Require Section 110(a)(2)(D) Submissions in Accordance With the Schedule of Section 110(a)(1)

A number of commenters objected to EPA's proposal to require States to submit the transport SIPs on the schedule set forth in section 110(a)(1). The commenters argued that section 110(a)(1) does not apply to the requirements of section 110(a)(2)(D), because the former refers to plans that States must adopt ''to implement, maintain, and enforce'' the NAAQS ''within'' the State, whereas the latter refers to plans that prevent emissions that affect nonattainment or maintenance of the NAAQS in places outside the State. According to the commenters, because section 110(a)(1) SIPs purportedly need not address the interstate transport issues governed by section 110(a)(2)(D), the States have no current obligation to prevent such interstate transport and, by extension, there is no basis for the CAIR at this time.

The EPA disagrees with the commenters. A State's SIP must of course provide for ''implementation, maintenance, and enforcement'' of the NAAQS ''within'' the State because States lack authority to impose requirements on sources in other States; *i.e.*, any plan submitted by a State will necessarily be applicable to sources ''within'' that State. The CAA, however, also requires that such SIPs must be submitted to EPA no later than three years after promulgation of a new or revised NAAQS and must contain adequate provisions regarding interstate transport from emission sources within the State in compliance with section 110(a)(2)(D). The explicit terms of the statute provide for the State submission of initial SIPs after promulgation of a new NAAQS, and provide that such SIPs should address interstate transport. Section 110(a)(1) provides that:

> [e]ach State shall * * * adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) * * * a plan which provides for implementation, maintenance, and enforcement of such primary standard in each [area] within such State.

Section 110(a)(2) provides, in relevant part, that:

> [e]ach implementation plan submitted by a State under this Act shall be adopted by the State after reasonable notice and public hearing. Each such plan shall * * * (D) contain adequate provisions—(i) prohibiting * * * any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to [the NAAQS].

By referencing each implementation plan in section 110(a)(2), it is clear that the implementation plans required under section 110(a)(1) must satisfy the requirements of section 110(a)(2)(D). Thus, the plain meaning of these provisions, read together, is that SIP submissions are required within 3 years of promulgation of a new or revised NAAQS, and that the SIP submissions must meet the requirements of section 110(a)(2)(D).

By contrast, other requirements of section 110(a)(2) are not triggered by EPA's promulgation of a new or revised NAAQS, but rather by EPA's final designation of nonattainment areas. For example, section 110(a)(2)(I) by its terms indicates that State SIPs must meet that requirement not on the schedule of section 110(a)(1), but instead on the schedule of section 172(b).

The explicit distinction in the statute between requirements that States must meet on the schedule of section 110(a)(1) versus the schedule of section 172(b) reinforces the conclusion that States are to meet the initial requirements of section 110(a)(2)(D) within the schedule of section 110(a)(1).

In this context, it is important to note that the requirements of section 110(a)(1) plans are not limited to areas designated attainment, nonattainment, or unclassifiable.[114] Section 110(a)(1) requires each State to develop and submit a plan that provides for the implementation, maintenance, and enforcement of the NAAQS in ''each'' area of the State. Similarly, the requirement in section 110(a)(2)(D) that SIPs must prohibit interstate transport of air pollutants that significantly contribute to downwind nonattainment is not limited to any particular category of formally designated areas in the State. The provisions apply to emissions activities that occur anywhere in a state, regardless of its designation. If, as the commenters suggested, the requirements of section 110(a)(2)(D) plans are governed not by section 110(a)(1), but rather by the schedule of section 172, that would lead to the absurd result that upwind States need only reduce emissions from designated nonattainment areas to prevent significant contribution to nonattainment or interference with maintenance in a downwind State. Given that large portions of many upwind States may be designated as attainment for the NAAQS for local purposes, yet still contain large sources of emissions that affect downwind States through interstate transport, EPA believes that Congress could not have intended the prohibitions of section 110(a)(2)(D) to apply only to nonattainment areas in upwind States.[115] Indeed, the language of

[114] Under section 107(d), EPA is required to identify all areas of each State as falling into one of these three categories.

[115] The EPA notes that under the provisions of section 107(d), certain portions of an upwind State that are monitoring attainment may be designated nonattainment because they contribute to violations of the NAAQS in a ''nearby'' area. Nevertheless,

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section 110(a)(2) itself does not support such an interpretation. Therefore, the alternative schedule provided in section 172(b) applicable only to nonattainment areas cannot be the schedule that governs the State submission of transport SIPs. This leaves the schedule of section 110(a)(1) as the only appropriate schedule in the case of SIPs following EPA promulgation of new or revised NAAQS.

The commenters also disputed that the schedule of section 110(a)(1) applies to the section 110(a)(2)(D) requirement because there are other elements of section 110(a)(2) that States could not meet on that schedule. As an example, the commenters pointed to section 110(a)(2)(I) which requires States to meet certain obligations imposed upon designated nonattainment areas. As formal designation under the generally applicable provisions of section 107(d) could take up to 3 years following promulgation of a new or revised NAAQS, and section 172(b) allows up to 3 additional years for State submission of nonattainment area SIPs, the commenters concluded that States could not meet section 110(a)(2)(I) on the schedule of section 110(a)(1). From the fact that States could not meet all of the elements of the section 110(a)(2) requirement within 3 years, the commenters inferred that EPA cannot require States to meet any of the requirements in section 110(a)(2), including section 110(a)(2)(D).

The EPA disagrees with the commenters' approach to the interpretation of the statute. The EPA agrees that there are certain provisions of section 110(a)(2) that are governed not by the schedule of section 110(a)(1), but instead by the timing requirement of section 172(b), *e.g.*, section 110(a)(2)(I). Other items in section 110(a)(2), however, do not depend upon prior designations in order for States to develop a SIP to begin to comply with them, *e.g.*, section 110(a)(2)(B) (pertaining to monitoring); section 110(a)(2)(E) (stipulating that States must provide for adequate resources); and section 110(a)(2)(K) (pertaining to modeling).

Most important, section 110(a)(2)(D) itself does not apply only to impacts on downwind nonattainment areas, and thus does not presuppose prior designations in either upwind or downwind States, or suggest that section 110(a)(2)(D) is somehow inapplicable until the submission of nonattainment area plans. By its explicit terms, section 110(a)(2)(D) requires States to prohibit emissions from ''any source or other types of emissions activity within the State'' that ''contribute to nonattainment in, or interfere with maintenance by'' any other State. A plain reading of the statute indicates that the emissions at issue can emanate from any portion of an upwind State and that the impacts of concern can occur in any portion of the downwind State.

While EPA agrees that there is overlap between the submission requirements of sections 110(a)(1) and (a)(2) and section 172(c), EPA believes that the plain language of these sections requires States to submit plans that comply with section 110(a)(2)(D) prior to the deadline for nonattainment area SIPs established by section 172, and that there is nothing that compels a contrary conclusion in the language of section 172. Section 172(b) provides that State plans for nonattainment areas must meet ''*the applicable* requirements of [section 172(c)] and section 110(a)(2)'' (emphasis added). Thus, the statute itself explicitly indicates that the State submissions for nonattainment plans must meet those requirements of section 110(a)(2) that are ''applicable,'' not each requirement regardless of applicability. In the current situation, EPA believes that it is appropriate to view the CAA as requiring States to make a submission to meet the requirement of section 110(a)(2)(D) in accordance with the schedule of section 110(a)(1), rather than under the schedule for nonattainment SIPs in section 172(b).[116]

b. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to Formal Designation of Nonattainment Areas Under Section 107

A number of commenters argued that EPA has no authority to require States to comply with section 110(a)(2)(D) until after EPA formally designates nonattainment areas for the $PM_{2.5}$ and 8-hour ozone NAAQS.[117] These commenters claimed that section 107(d) and provisions of the Transportation Equity Act for the 21st Century (TEA–21) governing the designation of $PM_{2.5}$ and 8-hour ozone nonattainment areas preclude EPA from interpreting the CAA to require States to submit SIPs that comply with section 110(a)(2)(D) on the schedule contemplated by section 110(a)(1). In the view of the commenters, EPA could not reasonably expect States to determine whether and to what extent their in-State sources significantly contributed to nonattainment in other States within the initial 3-year timeframe, in advance of nonattainment area designations. According to the commenters, section 107(d) and TEA–21 negate the timing requirements of section 110(a)(1), so that States have no current obligation to address interstate transport and thus there is no basis for today's action.

The EPA disagrees with the commenters' view of the interaction of section 110 and section 107(d). The statute does not require EPA to have completed the designations process before the Agency or a State could assess the existence of, or extent of, significant contribution from one State to another. In addition, the technical approach by which EPA determines significant contribution from upwind to downwind States does not depend upon the prior completion of the designation process.

The EPA believes that the statute does not compel the conclusion that States may postpone compliance with section 110(a)(2)(D) until some future point after completion of the designation process. As discussed above, a reading of the plain language of sections 110(a)(1) and 110(a)(2) indicates that States must adopt and submit a plan to EPA within 3 years after promulgation of a new or revised NAAQS (the same time at which designations are generally due under section 107), and that each

there will be portions of upwind States that include emissions sources that are not in designated nonattainment areas, whether because of local monitored nonattainment, or because of contribution to a nearby nonattainment area, yet these portions of the upwind State may contain sources that cause emissions that States must address to meet the requirements of section 110(a)(2)(D).

[116] As noted earlier, what will be needed to meet section 110(a)(2) may vary, depending upon the specific facts and circumstances surrounding a new or revised NAAQS. *See, e.g., Proposed Requirements for Implementation Plans and Ambient Air Quality Surveillance for Sulfur Oxides (Sulfur Dioxide) National Ambient Air Quality Standard*, 60 FR 12492, 12505 (March 7, 1995). In the context of a proposed 5-minute NAAQS for SO_2, EPA tentatively concluded that existing SIP provisions for the 24-hour and annual SO_2 NAAQS were probably sufficient to meet many elements of section 110(a)(2). The EPA did not explicitly discuss State obligations under section 110(a)(2)(D) for the 5-minute NAAQS in the proposal, but the nature of the pollutant, the sources, and the proposed NAAQS are such that interstate transport would not have been the critical regionwide concern that it is for the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA does not expect States to make SIP submissions establishing emission controls for the purpose of addressing interstate transport without having adequate information available to them.

[117] The EPA notes that the 8-hour ozone designations became effective on June 15, 2004, and that the $PM_{2.5}$ designations will become effective on April 5, 2005. The EPA believes that the issue raised by the commenters is thus moot with respect to both the 8-hour ozone and $PM_{2.5}$ nonattainment areas because those designations are now complete.

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such plan must meet the applicable requirements of section 110(a)(2)(D).[118]

Significantly, neither section 110(a)(1) nor section 110(a)(2)(D) are limited to ''nonattainment'' areas. By their explicit terms, both provisions apply to all areas within the State, regardless of whether EPA has formally designated the areas as attainment, nonattainment, or unclassifiable, pursuant to section 107(d). As to causes, section 110(a)(2)(D) compels States to address any ''emissions activity within the State,'' not solely emissions from formally designated nonattainment areas, nor does it in any other terms suggest that designations of upwind areas must first have occurred. As to impacts, section 110(a)(2)(D) refers only to prevention of ''nonattainment'' in other States, not to prevention of nonattainment in designated nonattainment areas or any similar formulation requiring that designations for downwind nonattainment areas must first have occurred. By comparison, other provisions of the CAA do clearly indicate when they are applicable to designated nonattainment areas, rather than simply to nonattainment more generally (*e.g.*, sections 107(d)(1)(A)(i), 181(b)(2)(A), and 211(k)(10)(D)). Because section 110(a)(2)(D) refers only to ''nonattainment,'' not to ''nonattainment areas,'' EPA concludes that the section does not presuppose the existence of formally designated nonattainment areas, but rather to ambient air quality that does not attain the NAAQS.

The EPA believes that this plain reading of the provisions is also the most logical approach. A reading that section 110(a)(2)(D) means that States have no obligation to address interstate transport unless and until there are formally designated nonattainment areas pursuant to section 107 would be inconsistent with the larger goal of the CAA to encourage expeditious attainment of the NAAQS. In this immediate instance, currently available air quality monitoring data and modeling make it clear that many areas of the eastern portion of the country are in violation of both the $PM_{2.5}$ and 8-hour ozone NAAQS. Air quality modeling studies generally available to the States demonstrate that, and quantify the extent to which, SO_2 and NO_X emissions from sources in upwind States are contributing to violations of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind States.

Following the example of the NO_X SIP Call, EPA has an effective analytical approach to determine whether that interstate contribution is significant, in accordance with section 110(a)(2)(D). Thus, EPA currently has the information and tools that it needs to determine what the initial $PM_{2.5}$ and 8-hour ozone SIPs from upwind States should include as appropriate NO_X and SO_2 emissions reductions in order to prevent emissions that significantly contribute to nonattainment in downwind States. The designation process under section 107 is the means by which States and EPA decide the precise boundaries of the nonattainment areas in the downwind States. Both $PM_{2.5}$ and ozone are regional phenomena, however, and information as to the precise boundaries of nonattainment areas is not necessary to implement the requirements of section 110(a)(2)(D) for these pollutants. Consequently, it was not necessary for EPA to wait until after completion of formal designation of nonattainment area boundaries before undertaking this rulemaking. Moreover, EPA believes that taking action now will achieve public health protections more quickly as it will enable States to develop implementation plans more expeditiously and efficiently.

The EPA disagrees with the commenters' view of the relationship between section 110(a)(2) and section 107 and their apparent view of the method by which EPA analyzes whether there is a contribution from an upwind State to a downwind State, and whether that contribution is significant.

The EPA has, in this case, used the detailed data from the extensive network of air quality monitors to identify which States have monitors that are currently showing violations of the $PM_{2.5}$ and 8-hour ozone NAAQS. In the NPR, EPA stated that based upon data for the 3-year period from 2000–2002, ''120 counties with *monitors* exceed the annual $PM_{2.5}$ NAAQS and 297 counties with *monitor* readings exceed the 8-hour ozone NAAQS'' (69 FR 4566, 4581; January 30, 2004) (emphasis added). The geographic distribution of monitors with data registering current violations indicated that there is nonattainment of both the $PM_{2.5}$ and 8-hour ozone NAAQS throughout the eastern United States and in other portions of the country including California. For analyses of future ambient conditions, EPA used various modeling tools to predict that, in the absence of the CAIR, there would be counties with monitors that would continue to show violations of the $PM_{2.5}$ and 8-hour ozone NAAQS in 2010 and 2015. In subsequent steps, EPA analyzed whether the emissions from upwind States contributed to the ambient conditions at the monitors registering NAAQS violations in downwind States, and thereafter determined whether that contribution would be significant pursuant to section 110(a)(2)(D).

In none of these steps, however, did EPA need to know the precise boundaries of the nonattainment areas that may ultimately result from the section 107 designation process. The determination of attainment status in a given county is based primarily upon the monitored ambient measurements of the applicable pollutant in the county. Thus, it is the readings at the monitors that are the appropriate information for EPA to evaluate in assessing current and future interstate transport at that monitor in that county, not the exact dimensions of the area that may ultimately comprise the formally designated nonattainment area. The ultimate size of nonattainment areas will have a bearing on other components of the State's nonattainment area SIP. The size of such nonattainment areas, however, is not meaningful in assessing whether interstate transport from another State or States has an impact at a violating monitor, and whether the transport significantly contributes to nonattainment, that the other State or States should address to comply with section 110(a)(2)(D). Thus, EPA believes that basing the significant contribution analysis upon the counties with monitors that register nonattainment, without regard to the precise boundaries of the nonattainment areas that may ultimately result from the formal designation process under section 107, is the proper approach.

For similar reasons, EPA also disagrees with the commenters' assertion that the provisions of TEA–21 preclude EPA's interpretation of the timing requirements of sections 110(a)(1) and 110(a)(2). However, TEA–21 did address the need to create a new network of monitors to assess the geographic scope and location of $PM_{2.5}$ nonattainment. Also, TEA–21 did provide that such a network should be up and running by December 31, 1999. TEA–21 did lay out a schedule for the collection of data over a period of 3 years in order to make subsequent regulatory decisions. From these facts, the commenters concluded that TEA–21 necessarily contradicts EPA's position that States must now take action to address significant contribution to downwind nonattainment in their

[118] For reasons discussed in more detail above, EPA interprets the requirement of section 110(a)(2)(D) to be among those that Congress intended States to meet within the 3-year timeframe of section 110(a)(1). The EPA agrees that other requirements, such as those of section 110(a)(2)(I), are subject to the different timing requirements of section 172(b).

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initial section 110(a)(1) SIPs, merely because the initial 3-year period following the promulgation of a new or revised NAAQS specified in section 110(a)(1) has expired.

The EPA believes that nothing in TEA–21 explicitly or implicitly altered the timing requirements of section 110(a)(1) for compliance with section 110(a)(2)(D), although EPA recognizes that the data from monitoring funded by that Act contributed to the Agency's development of the SIP requirements in today's rulemaking. The provisions of TEA–21 pertained to the installation of a network of monitors for $PM_{2.5}$, and to the timing of designation decisions for $PM_{2.5}$ and 8-hour ozone. To be specific, TEA–21 had two primary purposes for the new NAAQS: (1) To gather information ''for use in the determination of area attainment or nonattainment designations'' for the $PM_{2.5}$ NAAQS; and (2) to ensure that States had adequate time to consider guidance from EPA concerning ''drawing area boundaries prior to submitting area designations'' for the 8-hour ozone NAAQS. TEA–21 sections 6101(b)(1) and (2). The EPA interprets the third stated purpose of TEA–21 to refer to ensuring consistency of timing between the Regional Haze program requirements and the $PM_{2.5}$ NAAQS requirements. With respect to timing, TEA–21 similarly only referred to the dates by which States and EPA should take their respective actions concerning designations. For $PM_{2.5}$, TEA–21 provided that States were required ''to submit designations referred to in section 107(d)(1) * * * within 1 year after receipt of 3 years of air quality monitoring data.'' TEA–21 section 6102(c)(1). For 8-hour ozone, TEA–21 required States to submit designation recommendations within 2 years after the promulgation of the new NAAQS, and required EPA to make final designations within 1 year after that (TEA–21 sections 6103(a) and (b)). In all of these provisions, TEA–21 only addresses SIP timing in the context of the designation process of section 107(d). As explained in more detail above, EPA does not believe that the timing of section 110(a)(1) and section 110(a)(2)(D) obligations depend upon the prior designation of areas in accordance with section 107(d).

The EPA also notes that legislation subsequent to TEA–21 further supports this conclusion. In the 2004 Consolidated Appropriations Act, Congress further amended section 107 to provide specific dates by which States and EPA must make $PM_{2.5}$ designations. 42 U.S.C. 7407 note. The Act now requires States to have made their initial recommendations for $PM_{2.5}$ designations by February 15, 2004, and requires EPA to take action on those recommendations and make its final designation decisions no later than December 31, 2004. Again, these requirements pertain only to formal designations, and do not directly affect the obligations of States to meet other SIP requirements. Neither TEA–21 nor the 2004 Appropriations Act language altered the section 110(a)(1) schedule for compliance with section 110(a)(2)(D).

The commenters suggested that because Congress provided more time for making formal designations pursuant to section 107, it necessarily follows that States should not have to meet the requirements of section 110(a)(2)(D) on the schedule of section 110(a)(1). The EPA believes that Congress did not, through TEA–21 or other actions, alter the existing submission schedule for SIPs to address interstate transport. By contrast, Congress did explicitly alter the schedule for submission of plan revisions to address Regional Haze. From this, EPA infers that Congress did not intend EPA to delay action to address the issue of interstate transport for the 8-hour or $PM_{2.5}$ NAAQS. Thus, EPA must still ensure that States submit SIPs in accordance with the substantive requirements of section 110(a)(2)(D). However, because EPA and the States now have the data and analyses to establish the presence and magnitude of interstate transport, in part through the monitoring data gathered pursuant to TEA–21, the Agency believes that that it is now appropriate to require States to address interstate transport at this time in the manner set forth in today's rule.

c. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to State Submission of Nonattainment Area Plans Under Section 172

Some commenters suggested that EPA cannot determine the existence of a significant contribution from upwind States to downwind States until EPA actually receives the nonattainment area SIPs from each State and evaluates how much ''residual'' nonattainment remains. If the reasoning of these commenters were adopted, downwind States would have to construct SIPs to attain the NAAQS without first knowing what upwind States might ultimately do to reduce interstate transport. Presumably, the theory is that the downwind States may choose to control their own local emissions sources more aggressively so that sources in upwind States could avoid installation of highly cost-effective emission controls, notwithstanding the continued significant impacts of emissions from upwind sources on downwind States. Alternatively, the rationale may be that EPA should wait until submission of upwind State nonattainment area SIPs to discover whether and to what degree the SIPs address interstate transport to downwind States.

For reasons already discussed more fully above, EPA does not believe that the statute requires a ''wait and see'' approach to discover what, if anything, States may ultimately do to address the problem of regional interstate transport. Section 110(a)(1) requires ''each'' State to submit a SIP within 3 years after a new or revised NAAQS addressing the requirements of section 110(a)(2)(D). When the data and the analyses needed to establish the existence of interstate transport of pollutants and to determine whether there is a significant contribution to nonattainment or interference with maintenance by one State in another State are available, as here after the monitoring funded by TEA–21, EPA believes that it may act upon that information prior to State SIP submissions to ensure that States address such contribution expeditiously, as it is doing in this rulemaking. The EPA believes it is a better policy to assist the States to address the regional component of the nonattainment problem in a way that is equitable, timely, cost effective, and certain.

The EPA acknowledges that historically, especially in the case of 1-hour ozone, the Agency has not had the data and the analytical tools to help upwind States to address interstate transport as early in the SIP process as it is doing today for $PM_{2.5}$ and 8-hour ozone. The CAA has required States to regulate ozone or its regulatory predecessors since 1970. For many years, States and EPA focused on the adoption and implementation of local controls to bring local nonattainment areas into attainment. Thus, historically, local areas bore the burden of achieving attainment through imposition of control measures on local sources. By comparison, upwind States did not have to adopt local controls in attainment areas and typically did not adopt such controls solely to lessen the impact of their emissions on downwind States. Since 1977, the CAA has also imposed a series of local control obligations on 1-hour ozone nonattainment areas, such as RACT for stationary sources, inspection and maintenance for mobile sources, and other requirements that became increasingly more stringent, based upon the level of local nonattainment. In spite of these local control efforts, there continued to be a

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widespread problem with nonattainment that resulted, in part, from unaddressed interstate transport. A lack of information and analytical tools hindered the ability of EPA and the States to address the regional interstate transport component of 1-hour ozone nonattainment, until the NO_X SIP Call in 1998. While it is thus true that the NO_X SIP Call postdated the submission of nonattainment area SIPs, this should not be construed as evidence that the statute precludes the States and EPA from addressing interstate transport earlier in the process for the 8-hour ozone and $PM_{2.5}$ NAAQS.

Given that EPA and the States indisputably have the requisite information to identify interstate transport at this stage of SIP development, EPA believes, based upon its experience in implementing the 1-hour ozone NAAQS, that it is preferable to take action under section 110(a)(2)(D) to address the regional transport component of the $PM_{2.5}$ and 8-hour ozone nonattainment problem. States, both upwind and downwind, will still have an obligation to control emissions from sources within their boundaries for the purposes of local area attainment and maintenance of the NAAQS. The EPA does not believe, however, that it is either required by the statute, or in accordance with sound policy, for the Agency to wait until submission of the nonattainment area SIPs of downwind States to discover whether or not those SIPs will control local sources sufficiently to provide for eventual attainment regardless of continued significant contribution through interstate transport from upwind States. To the contrary, past experience with the 1-hour ozone NAAQS has demonstrated that delayed action to address the interstate component of nonattainment will potentially lead to delays in attainment as downwind areas struggle to overcome the impacts of transport. Indeed, a number of scientific and technical assessments of ozone and $PM_{2.5}$ by the NRC and the Ozone Transport Assessment Group have identified addressing interstate transport as a critical issue in developing SIPs.

d. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to Completion of the Next Review of the $PM_{2.5}$ and 8-Hour Ozone NAAQS

Commenters also asserted that EPA should not take any action to implement the 8-hour ozone and $PM_{2.5}$ NAAQS, until completion of the next NAAQS review cycle. According to the commenters, a series of statements by EPA and others indicated an intention to take no action to implement the NAAQS until after the next review cycle, and that statutes passed by Congress confirm that EPA is to take no such action.

The EPA disagrees with the assertion that it should take no action to implement the 1997 $PM_{2.5}$ and 8-hour ozone NAAQS until completion of the next NAAQS review. Section 110(a) explicitly requires States to begin to submit SIPS within 3 years after promulgation of a new or revised NAAQS. The CAA also requires EPA to take action upon State SIP submissions within specific timeframes. States are likewise explicitly obligated to attain existing NAAQS within certain specified timeframes. None of these basic statutory submission, review, or attainment obligations are stayed or delayed due to the fact that there may be an ongoing NAAQS review cycle. Indeed, under section 109, EPA is to review all NAAQS on an ongoing basis, every 5 years. If the mere existence of a NAAQS review cycle were grounds to suspend implementation of a NAAQS, it would undermine the very goals of the statute.

The commenters argued that certain statements made by EPA and others in guidance memoranda and elsewhere preclude EPA from taking any action to implement the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA believes that the commenters are misconstruing those statements, and that the statements merely reflect the Agency's assumption that the NAAQS review cycle would occur on the normal schedule. It would be nonsensical to suggest that, if for any reason, the NAAQS review cycle were delayed, that the CAA would permit no implementation of the existing NAAQS. Such an approach would invite and encourage inappropriate interference in the NAAQS review cycle as a means of subverting the CAA.

The commenters further argued that Congress has taken action to prevent implementation of the 8-hour ozone and $PM_{2.5}$ NAAQS pending the next NAAQS review cycle. The EPA does not see any such intention on the part of Congress. In TEA–21 and the 2004 Consolidated Appropriations Act, Congress has amended section 107 to provide specific dates by which States and EPA must make designations. Significantly, Congress did not alter the existing statute with respect to any other deadlines for SIP submissions, or with respect to implementation of the $PM_{2.5}$ and 8-hour ozone NAAQS generally. By contrast, in the 2004 Consolidated Appropriations Act, Congress did explicitly alter the date by which States must submit plan revisions to address Regional Haze. See, Section 7(A), 42 U.S.C. section 7407 note. From this explicit action, one must infer that Congress could have taken action to alter the submission date for plans to address $PM_{2.5}$ or 8-hour ozone, had it intended to alter the existing statutory scheme. Most importantly, however, Congress did not make any of the changes effected in TEA–21 or the 2004 Consolidated Appropriations Act dependent upon completion of the next NAAQS review. To the contrary, Congress directed EPA to take certain actions notwithstanding the fact that there were and are ongoing reviews of the NAAQS. From this, EPA infers that Congress did not intend EPA to defer all action to implement the existing NAAQS, including today's action to assist States to address the requirements of section 110(a)(2)(D).

e. The EPA's Authority To Require States To Make Section 110(a)(2)(D) Submissions Within 18 Months of This Final Rule

Some commenters questioned EPA's proposal to require States to make SIP submissions in response to this action as expeditiously as practicable but no later than within 18 months. A number of commenters suggested that this schedule is too short because of the magnitude or complexity of the task or because of the typical duration of State rulemaking processes. Other commenters suggested that EPA should follow the example of the NO_X SIP Call more closely and provide a shorter period than the Agency proposed.

The EPA has concluded that the proposed 18-month schedule is reasonable given the circumstances and given the scope of the actions that we are requiring States to take. We issued the $PM_{2.5}$ and 8-hour ozone NAAQS revisions in July 1997. More than 3 years have already elapsed since promulgation of the NAAQS, and States have not submitted SIPs to address their section 110(a)(2)(D) obligations under the new NAAQS. We recognize that litigation over the new $PM_{2.5}$ and 8-hour ozone NAAQS created substantial uncertainty as to whether the courts would uphold the new NAAQS, and that this uncertainty, as a practical matter, rendered it more difficult for States to develop SIPs. Moreover, in the case of $PM_{2.5}$, additional time was needed for creation of an adequate monitoring network, collection of at least 3 years of data from that network, and analysis of those data.

In addition, in the NPR, the SNPR, and today's action, we have provided States with a great deal of data and analysis concerning air quality and control costs, as well as policy judgments from EPA concerning the appropriate criteria for determining whether upwind sources contribute significantly to downwind nonattainment under section 110(a)(2)(D). We recognize that States would face great difficulties in developing transport SIPs to meet the requirements of today's action without these data and policies. In light of these factors and the fact that States can no longer meet the original 3-year submittal date of section 110(a)(1), we believe that States need a reasonable period of time in which to comply with the requirements of today's action.

In the comparable NO_X SIP Call rulemaking, EPA provided 12 months for the affected States to submit their SIP revisions. One of the factors that we considered in setting that 12-month period was that upwind States had already, as part of the Ozone Transport Assessment Group process begun 3 years before the NO_X SIP Call rulemaking, been given the opportunity to consider available control options. Because today's action requires affected States to control both SO_2 and NO_X emissions, and to do so for the purpose of addressing both the $PM_{2.5}$ and 8-hour ozone NAAQS, we believe it is reasonable to allow affected States more time than was allotted in the NO_X SIP Call to develop and submit transport SIPs.

Another factor that we have considered is that under section 110(k)(5), the CAA stipulates that EPA may provide up to 18 months for SIP submissions to correct substantially inadequate plans. While today's action is not pursuant to section 110(k)(5), we believe that the provision provides an analogy for the appropriate schedule on which EPA should expect States to make the submission required by today's action. We believe it would not be appropriate to set a longer schedule for submission of the plan than would have been possible under section 110(k)(5) had the States submitted a plan on the original 3-year schedule contemplated in section 110(a)(1) that did not provide for the emissions reductions today's action requires. While the CAA does require States to make some SIP submissions on shorter schedules, we conclude that the complexities of the action required by today's rulemaking militate in favor of a longer schedule.[119]

Finally, we note that by making findings that States have thus far failed to submit SIPs to meet the requirements of section 110(a)(2)(D) for the 8-hour ozone and $PM_{2.5}$ NAAQS, EPA has an obligation to implement a Federal implementation plan (FIP) to address interstate transport no later than 24 months after that finding, if the States fail to take appropriate action. Given this schedule for the FIP obligation, EPA believes that it is reasonable to require States to take action to meet the section 110(a)(2)(D) obligation with respect to the significant contribution identified in today's rule within no more than 18 months. Such a schedule will allow States adequate time to develop submissions to meet this requirement and will afford EPA adequate time to review such submissions before the imposition of a FIP in lieu of a SIP, if necessary.

Thus, EPA has concluded that States should submit SIPs to reduce interstate transport, as required by this final action, as expeditiously as practicable but no later than 18 months from today's date. Such a schedule will provide both upwind and downwind States, and those States that are in both positions relative to other States, to develop SIPs that will facilitate expeditious attainment of the $PM_{2.5}$ and the 8-hour ozone standards.

C. What Happens If a State Fails To Submit a Transport SIP or EPA Disapproves the Submitted SIP?

1. Under What Circumstances Is EPA Required To Promulgate a FIP?

Under section 110(c)(1), EPA is required to promulgate a FIP within 2 years of: (1) finding that a State has failed to make a required submittal; or (2) finding that a submittal received does not satisfy the minimum completeness criteria established under section 110(k)(1)(A) (40 CFR part 51, appendix V); or (3) disapproving a SIP submittal in whole or in part. Section 110(c)(1) mandates that EPA promulgate a FIP unless the States corrects the deficiency and EPA approves the SIP before the time EPA would promulgate the FIP.

2. What Are the Completeness Criteria?

Any SIP submittal that is made with respect to the final CAIR requirements first would be determined to be either incomplete or complete. A finding of completeness is not a determination that the submittal is approvable. Rather, it means the submittal is administratively and technically sufficient for EPA to proceed with its review to determine whether the submittal meets the statutory and regulatory requirements for approval. Under 40 CFR 51.123 and 40 CFR 51.124 (the proposed new regulations for NO_X and SO_2 SIP requirements, respectively), a submittal, to be complete, must meet the criteria described in 40 CFR, part 51, appendix V, ''Criteria for Determining the Completeness of Plan Submissions.'' These criteria apply generally to SIP submissions.

Under CAA section 110(k)(1) and section 1.2 of appendix V, EPA must notify States whether a submittal meets the requirements of appendix V within 60 days of, but no later than 6 months after, EPA's receipt of the submittal. If a completeness determination is not made within 6 months after submission, the submittal is deemed complete by operation of law. For rules submitted in response to the CAIR, EPA intends to make completeness determinations expeditiously.

3. When Would EPA Promulgate the CAIR Transport FIP?

The EPA views seriously its responsibility to address the issue of regional transport of $PM_{2.5}$, ozone, and precursor emissions. Decreases in NO_X and SO_2 emissions are needed in the States named in the CAIR to enable the downwind States to develop and implement plans to achieve the $PM_{2.5}$ and 8-hour ozone NAAQS and provide clean air for their residents. Thus, EPA intends to promulgate the FIP shortly after the CAIR SIP submission deadline for States that fail to submit approvable SIPs in order to help assure that the downwind States realize the air quality benefits of regional NO_X and SO_2 reductions as soon as practicable. This is consistent with Congress' intent that attainment occur in these downwind nonattainment areas ''as expeditiously as practicable'' (sections 181(a),172(a)). To this end, EPA intends to propose the FIP prior to the SIP submission deadline.

The FIP proposal would achieve the NO_X and SO_2 emissions reductions required under the CAIR by requiring EGUs in affected States to reduce emissions through participation in Federal NO_X and SO_2 cap and trade programs. The EPA intends to integrate these Federal trading programs with the model trading programs that States may choose to adopt to meet the CAIR. Although EPA would be proposing FIPs for all States affected by the CAIR, EPA will only issue a final FIP for those jurisdictions that fail to respond adequately to the CAIR.

[119] See, *e.g.,* section 182(a)(2)(A) (providing a 6-month schedule for submission of a revision to provide for RACT corrections); section 189(d) (providing 12 months for submission of plan revisions to ensure attainment and required emissions reductions). The former revision could be relatively limited in scope, but the latter might entail submission of a completely revised SIP.

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The EPA's goal is to have approvable SIPs that meet the requirements of the CAIR. We remain ready to work with the States to develop fully approvable SIPs, which would eliminate the need for EPA to promulgate a FIP.

D. What Are the Emissions Reporting Requirements for States?

The EPA believes that it is essential that achievement of the emissions reductions required by the CAIR be verified on a regular basis. Emission reporting is the principal mechanism to verify these reductions and to assure the downwind affected States and EPA that the ozone and $PM_{2.5}$ transport problems are being mitigated as required by the rule. Therefore, the final rule establishes a small set of new emission reporting requirements applicable to States affected by the CAIR, covering certain emissions data not already required under existing emission reporting regulations. The rule language also removes a current emission reporting requirement related to the NO_X SIP call, which we believe is not necessary, for reasons explained below. A number of other proposed changes in emission reporting requirements which would have affected States not subject to the final CAIR are not included in the final rule, for reasons explained below. We will repropose these other changes, with modifications, in a separate proposal to allow additional opportunity for public comment.

1. Purpose and Authority

Because we are consolidating and harmonizing the new emission reporting requirements promulgated today with two pre-existing sets of emission reporting requirements, we review here the purpose and authority for emission reporting requirements in general.

Emissions inventories are critical for the efforts of State, local, and Federal agencies to attain and maintain the NAAQS that EPA has established for criteria pollutants such as ozone, PM, and CO. Pursuant to its authority under sections 110 and 172 of the CAA, EPA has long required SIPs to provide for the submission by States to EPA of emissions inventories containing information regarding the emissions of criteria pollutants and their precursors (*e.g.*, VOCs). The EPA codified these requirements in subpart Q of 40 CFR part 51, in 1979 and amended them in 1987.

The 1990 Amendments to the CAA revised many of the provisions of the CAA related to the attainment of the NAAQS and the protection of visibility in Class I areas. These revisions established new periodic emissions inventory requirements applicable to certain areas that were designated nonattainment for certain pollutants. For example, section 182(a)(3)(A) required States to submit an emissions inventory every 3 years for ozone nonattainment areas beginning in 1993. Similarly, section 187(a)(5) required States to submit an inventory every 3 years for CO nonattainment areas. The EPA, however, did not immediately codify these statutory requirements in the CFR, but simply relied on the statutory language to implement them.

In 1998, EPA promulgated the NO_X SIP call which requires the affected States and the District of Columbia to submit SIP revisions providing for NO_X reductions to reduce their adverse impact on downwind ozone nonattainment areas. (63 FR 57356, October 27, 1998). As part of that rule, codified in 40 CFR 51.122, EPA established emissions reporting requirements to be included in the SIP revisions required under that action.

Another set of emissions reporting requirements, termed the Consolidated Emissions Reporting Rule (CERR), was promulgated by EPA in 2002, and is codified at 40 CFR part 51 subpart A. (67 FR 39602, June 10, 2002). These requirements replaced the requirements previously contained in subpart Q, expanding their geographic and pollutant coverages while simplifying them in other ways.

The principal statutory authority for the emissions inventory reporting requirements outlined in this final rule is found in CAA section 110(a)(2)(F), which provides that SIPs must require ''as may be prescribed by the Administrator * * * (ii) periodic reports on the nature and amounts of emissions and emissions-related data from such sources.'' Section 301(a) of the CAA provides authority for EPA to promulgate regulations under this provision.[120]

2. Pre-existing Emission Reporting Requirements

As noted above, prior to this final rule, two sections of title 40 of the CFR contained emissions reporting requirements that are applicable to States: Subpart A of part 51 (the CERR) and section 51.122 in subpart G of part 51 (the NO_X SIP Call reporting requirements).

[120] Other CAA provisions relevant to this final rule include section 172(c)(3) (provides that SIPs for nonattainment areas must include comprehensive, current inventory of actual emissions, including periodic revisions); section 182(a)(3)(A) (emissions inventories from ozone nonattainment areas); and section 187(a)(5) (emissions inventories from CO nonattainment areas).

Under the NO_X SIP Call requirements in section 51.122, emissions of NO_X for a defined 5-month ozone season (May 1 through September 30) and for work weekday emissions for point, area and mobile sources that the State has subjected to emissions control to comply with the requirements of the NO_X SIP Call, are required to be reported by the affected States to EPA every year. However, emissions of sources reporting directly to EPA as part of the NO_X trading program are not required to be reported by the State to EPA every year. The affected States are also required to report ozone season emissions and typical summer daily emissions of NO_X from all sources every third year (2002, 2005, etc.) and in 2007. This triennial reporting process does not have an exemption for sources participating in the emissions trading programs. Section 51.122 also requires that a number of data elements be reported for each source in addition to ozone season NO_X emissions. These data elements describe certain of the source's physical and operational parameters.

Emissions reporting under the NO_X SIP Call as first promulgated was required starting for the emissions reporting year 2002, the year prior to the start of the required emissions reductions. The reports are due to EPA on December 31 of the calendar year following the inventory year. For example, emissions from all sources and types in the 2002 ozone season were required to be reported on December 31, 2003. However, because the Court which heard challenges to the NO_X SIP Call delayed the implementation by 1 year to 2004, no State was required to start reporting until the 2003 inventory year. The EPA promulgated a rule to subject Georgia and Missouri to the NO_X SIP Call with an implementation date of 2007. (*See* 69 FR 21604, April 21, 2004.) We have recently proposed to stay the NO_X SIP Call for Georgia (*see* 70 FR 9897, March 1, 2005). Missouri's emissions reporting begins with 2006. These emissions reporting requirements under the NO_X SIP Call affect the District of Columbia and 18 of the 28 States affected by the proposed CAIR.

As noted above, the other set of pre-existing emissions reporting requirements is codified at subpart A of part 51. Although entitled the Consolidated Emissions Reporting Rule (CERR), this rule left in place the separate § 51.122 for the NO_X SIP Call reporting. The CERR requirements were aimed at obtaining emissions information to support a broader set of purposes under the CAA than were the reporting requirements under the NO_X

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SIP Call. The CERR requirements apply to all States.

Like the requirements under the NO_X SIP Call, the CERR requires reporting of all sources at 3-year intervals (2005, 2008, etc.). It requires reporting of certain large sources every year. However, the required reporting date under the CERR is 5 months later than under the NO_X SIP Call reporting requirements. Also, emissions must be reported for the whole year, for a typical day in winter, and a typical day in summer, but not for the 5-month ozone season as is required by the NO_X SIP Call. Finally, the CERR and the NO_X SIP Call differ in what non-emissions data elements must be reported.

3. Summary of the Proposed Emissions Reporting Requirements

On June 10, 2004, EPA published a SNPR (69 FR 32684) to EPA's January 30, 2004 proposal (69 FR 4566). The EPA's main objective with respect to emissions reporting was to add limited new requirements for emissions reports to serve the additional purposes of verifying the CAIR-required emissions reductions. The SNPR also sought to harmonize the CERR and NO_X SIP Call reporting requirements with respect to specific data elements and consolidate them entirely in subpart A, and to reduce and simplify the reporting requirements in several ways. These latter changes were proposed to be applicable to all States, not just those affected by the CAIR emissions reduction requirements. The major changes included in the SNPR are described below.

Amendments were proposed to subpart A, which contains § 51.1 through 51.45 and an appendix, and to § 51.122. We also proposed to add a new § 51.125.

- In § 51.122, the NO_X SIP Call provisions, we proposed to abolish certain requirements entirely, and to replace certain requirements with a cross reference to subpart A so that detailed lists of required data elements appeared only in subpart A. As proposed, § 51.122 would then have specified what pollutants, sources, and time periods the States subject to the NO_X SIP Call must report and when, but would no longer have listed the detailed data elements required for those reports.
- The proposed new § 51.125 would have been functionally parallel to § 51.122, specifying all the pollutants, sources, and time periods the States subject to the proposed CAIR must report and when, referencing subpart A for the detailed data elements required.
- The proposed amended subpart A would have listed the detailed data elements for all three reporting programs (CERR, NO_X SIP Call, and CAIR) as well as provided information on submittal procedures, definitions, and other generally applicable provisions.

Taken together, the pre-existing emissions reporting requirements under the NO_X SIP Call and CERR were already rather comprehensive in terms of the States covered and the information required. Therefore, the practical impact of the proposed changes would have imposed only three new requirements.

First, in Arkansas, Florida, Iowa, Louisiana, Mississippi, and Wisconsin for which we proposed and are finalizing a finding of significant contribution to ozone nonattainment in another State but which were not among the 22 States already subject to the NO_X SIP Call, the required emissions reporting would be expanded to match those of the 22 States. The proposed change would require that they report NO_X emissions during the 5-month ozone season and for a typical summer day, in addition to the existing requirement for reporting emissions for the full year. We proposed that this new requirement begin with the triennial inventory year prior to the CAIR implementation date. This would be the 2008 inventory year, the report for which would be due to EPA by June 1, 2010.

Second, under the existing CERR, yearly reporting is required only for sources whose emissions exceed specified amounts. The SNPR proposed that the 28 States and the District of Columbia subject to the CAIR for reasons of $PM_{2.5}$ must report to EPA each year a set of specified data elements for all sources subject to new controls adopted specifically to meet the CAIR requirements related to $PM_{2.5}$, unless the sources participate in an EPA-administered emissions trading program. We proposed that this new requirement begin with the 2009 inventory year, the report for which will be due to EPA by June 1, 2011. This new requirement would have no effect on States that fully comply with the CAIR by requiring their EGUs to participate in the CAIR model cap and trade programs.

Third, in all States, we proposed to expand the definition of what sources must report in point source format, so that fewer sources would be included in non-point source emissions.[121] We proposed to base the requirement for point source format reporting on whether the source is a major source under 40 CFR part 70 for the pollutants for which reporting is required, *i.e.,* for CO, VOC, NO_X, SO_2, $PM_{2.5}$, PM_{10} and ammonia but without regard to emissions of hazardous air pollutants.

A number of other proposed changes would have reduced reporting requirements on States or provided them with additional options. Two of the proposed changes in this category are of special note in understanding the final requirements of today's rule. (The remainder of these changes were explained in the SNPR at 69 FR 32697.)

- The NO_X SIP Call rule requires the affected States to submit emissions inventory reports for a given ozone season to EPA by December 31 of the following year. The CERR requires similar but not identical reports from all States by the following June 1, five months later. We proposed to move the December 31 reporting requirement to the following June 1, the more generally applicable submission date affecting all 50 States. We asked for comment on whether allowing this 5-month delay is consistent with the air quality goals served by the emissions reporting requirements. However, we also asked for comment on the alternative of moving forward to December 31 all or part of the June 1 reporting for all 50 States. In particular, we solicited comment on requiring that point sources be reported on December 31 and other sources on June 1.
- We also proposed to eliminate a requirement of the NO_X SIP Call for a special all-sources report by affected States for the year 2007, due December 31, 2008.

4. Summary of Comments Received and EPA's Responses

A number of commenters objected to the 45-day comment period as being too short to allow for full understanding of and comment on the emissions reporting changes that EPA had proposed. With respect to this issue, EPA believes that the comment period was sufficient for those proposed changes that would affect the States subject to the emissions reductions

[121] We used the term ''non-point source'' in the SNPR to refer to a stationary source that is treated for inventory purposes as part of an aggregated source category rather than as an individual facility. In the existing subpart A of part 51, such emissions sources are referred to as ''area sources.'' However, the term ''area source'' is used in section 112 of the CAA to indicate a non-major source of hazardous air pollutants, which could be a point source. As emissions inventory activities increasingly encompass both NAAQS-related pollutants and hazardous air pollutants, the differing uses of ''area source'' can cause confusion. Accordingly, EPA proposed to substitute the term ''non-point source'' for the term ''area source'' in subpart A, § 51.122, and the new § 51.125 to avoid confusion. We are not finalizing this change in terminology in today's rule.

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requirements of the CAIR and that are specifically directed at ensuring the effectiveness of the CAIR, namely: (1) The requirement for six more States to report ozone season emissions, and (2) the requirement for all subject States to report annual emissions from controlled sources every year if those sources are not participating in the emission trading programs. These proposed changes are easy to understand on their face, and also have close precedents in the NO_X SIP Call. Moreover, the States affected by these proposed reporting requirements were identified as being subject to the proposed emissions reduction requirements of the CAIR in the original NPR, and thus they knew to be alert to the contents of the SNPR. We also consider the comment period sufficient with respect to two other specific elements of the proposal, namely (3) the proposal to eliminate the 2007 inventory reporting requirement under the NO_X SIP Call and (4) the proposal to change the reporting date for the NO_X SIP Call from December 31 (12 months after the end of the reported year) to June 1 (17 months after the end of the reported year). These were also readily understood proposals, and the States affected by them were among those initially identified as subject to the CAIR itself. A number of substantive comments were received on these four proposed changes. Therefore, we have concluded that it is appropriate to consider the substantive comments that were received on these four elements of the SNPR, and to take final action on them. The disposition of the remaining elements of the SNPR is discussed further below.

The EPA received one comment from the Mississippi Department of Environmental Quality on the proposed requirement that Mississippi and five other States report ozone season emissions. Mississippi disagreed that they should be included with the other States subject to the CAIR provisions, including the emissions reporting provisions. The EPA has concluded that the analysis performed to support CAIR and discussed earlier in this preamble amply demonstrates that Mississippi should be included in the CAIR and subject to the CAIR emissions reporting requirements.

We did not receive comments specifically on the proposal to require States to report annual emissions every year from sources controlled to comply with the CAIR, if those sources are not participating in the emission trading programs operated by EPA. While we expect the number of such sources to be small if not zero, we continue to believe that tracking their emissions from year to year is appropriate, and we are finalizing this requirement. Since the CERR already contains a requirement for every-year reporting of emissions from point sources above certain emission thresholds, this requirement will have an incremental impact only if States choose to control fairly small point sources or nonpoint or mobile sources as part of their plan for meeting the CAIR requirements.

The EPA received several comments regarding the elimination of the NO_X SIP Call special all-sources 2007 emissions inventory. These comments all favored the elimination of the 2007 emissions inventory, which EPA is promulgating in today's rule. We would like to clarify that the NO_X SIP Call contained no requirement that any State make a retrospective demonstration that actual statewide emissions of NO_X were within any limit. The requirement for the 2007 inventory was for the purpose of program evaluation by EPA. As explained in the SNPR, we believe that in light of the data on 2007 emissions that will be available from the NO_X trading program and the further reductions in NO_X required by the CAIR, the 2007 inventory submissions from the States are not needed for this purpose.

The EPA also proposed to harmonize the report due dates for the NO_X SIP Call, currently 12 months after the end of the reported year, and for the CERR, currently 17 months after the end of the reported year. The EPA proposed to harmonize the dates for both at 17 months, but asked for comments on a 12-month due date. Several comments were received, all favoring harmonizing the report due date at 17 months. While we continue to believe in the efficiency advantage of harmonized submission date requirements, we are not finalizing this change. The EPA has reconsidered this part of the proposed emissions reporting requirements and believes that it may be in the interest of the public to move in the direction of shortening the emissions reporting cycle for all three reporting requirements (CERR, NO_X SIP Call, and CAIR), rather than accepting the longer CERR cycle for all three reporting requirements. In today's final rule, we are retaining the 12-month submission date requirement of the original NO_X SIP Call for the States already subject to it. For the six States that are newly subject to reporting ozone season NO_X emissions and for the new requirement for every-year reporting by sources controlled to meet the CAIR requirements for SO_2 and NO_X annual emissions reductions but not included in the trading programs, the required reporting date for States will be June 1, 17 months after the end of the reported year, as was proposed. We will address reporting deadlines comprehensively in a separate NPR which will propose a unified, but shorter period of time to report to EPA. This separate notice will allow for more public comment on the reporting cycle. The dual approach to reporting due dates retained in today's rule will be combined into unified due dates and will be influenced by comments received in response to our proposal when the separate rulemaking is completed.

Regarding elements of the proposed requirements beyond these four, i.e., the requirements that would have affected States not subjected to the CAIR emissions reduction requirements as well as CAIR States, many commenters said that EPA should not have included changes to national emissions reporting requirements in a proposed rule placing emissions reduction requirements on only certain States. Commenters also questioned whether EPA had given adequate time for comment on the more detailed revisions in required data elements, definitions, etc. Substantively, many commenters supported some or all of the proposed changes, but some commenters objected to some of them.

The EPA has considered these comments. Without conceding EPA's legal authority to include these provisions in the final rule in light of the history of proposal, public hearing, and comment period, EPA has—in an abundance of caution—decided to omit these provisions from today's rule (see section VIII.D.5 Summary of the Emissions Reporting Requirements below for the changes which are being finalized today). We will repropose them, with modifications, in a separate NPR to allow additional opportunity for public comment by all affected States and other parties.

5. Summary of the Emissions Reporting Requirements

As a result of the comments received, EPA has revised the emissions reporting requirements of today's rule by limiting new requirements to the ones where sufficient notice and opportunity for comment was clearly given in the June 10, 2004, SNPR and that either: (1) Are necessary for the monitoring of the implementation of the emissions reduction requirements of the CAIR, or (2) are changes in reporting under the NO_X SIP Call linked to the CAIR. Three specific emissions reporting provisions that change the pre-existing requirements are included in today's rule.

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1. Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin and the District of Columbia, which are subject to the CAIR for reasons of ozone, are made subject to emission reporting requirements for NO_X that are very similar to the existing requirements of the NO_X SIP Call, which already affects all but six of these States. For these six States (Arkansas, Florida, Iowa, Louisiana, Mississippi and Wisconsin) a new requirement is that they report NO_X emissions during the 5-month ozone season from all sources every three years, in addition to reporting emissions for the full year and for a summer day as was already required. This new requirement begins with the triennial inventory year 2008. For all the listed States, a new requirement is to report to EPA for 2009 and each year thereafter the ozone-season and summer day NO_X emissions, plus a set of specified other data elements, for all sources subject to new controls adopted specifically to meet the CAIR requirements related to ozone, unless the sources participate in an EPA-administered emissions trading program. These reports will be due June 1 of the second year following the end of the reported year, *i.e.*, 17 months after the end of the reported year. The existing CERR includes several other reporting requirements which in conjunction with this new requirement will meet the needs for monitoring the implementation of required NO_X emissions reductions.

2. Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin and the District of Columbia, which are subject to the CAIR for reasons of $PM_{2.5}$, must report to EPA each year annual NO_X and SO_2 emissions, plus a set of specified other data elements, for all sources subject to new controls adopted specifically to meet the CAIR requirements related to $PM_{2.5}$, unless the sources participate in an EPA-administered emissions trading program. Previously, these states may have been required to report these sources only every third year, depending on their size. The existing CERR includes several other reporting requirements which in conjunction with this new requirement will meet the needs for monitoring the implementation of required NO_X and SO_2 emissions reductions.

3. The EPA has determined that the requirement in the NO_X SIP Call for a special all-sources report by affected States for the year 2007, due December 31, 2008, is no longer needed to administer provisions in the NO_X SIP Call. Accordingly, EPA is eliminating this requirement in today's rule.

The final rule accomplishes these changes by making minimal changes to the existing provisions of 40 CFR part 51. Subpart A, which contains the CERR requirements, is not amended at all. 40 CFR 51.122, the section containing emission inventory reporting requirements for the NO_X SIP Call, is substantively amended only to delete the requirement for the 2007 inventory report.[122] A new section 40 CFR 51.125 is added to contain the two new emission inventory reporting requirements specifically related to the new CAIR requirements for emissions reductions, regarding ozone-season emissions of NO_X and every-year reporting of NO_X and SO_2 emissions from all sources controlled but not participating in the EPA trading programs. The new 40 CFR 51.125 refers to 40 CFR subpart A for the other specific data elements that must be reported.

VIII. Model NO_X and SO_2 Cap and Trade Programs

A. What Is the Overall Structure of the Model NO_X and SO_2 Cap and Trade Programs?

The EPA is finalizing model rules for the CAIR annual NO_X, CAIR ozone-season NO_X, and SO_2 trading programs that States can use to meet the emission reduction requirements in the CAIR. These rules are designed to be referenced by States in State rulemaking. State use of the model cap and trade rules helps to ensure consistency between the State programs, which is necessary for the market aspects of the regional trading program to function properly. It also allows the CAIR Program to build on the successful Acid Rain Program. Consistency in the CAIR requirements from State-to-State benefits the affected sources, as well as EPA, which administers the program on behalf of States.

This section focuses on the structure which maintains the existing NO_X SIP Call rules (in part 96, subparts A through J) while adding parallel rules for the CAIR annual NO_X (in subparts AA through II), CAIR SO_2 (in subparts AAA through III), and the CAIR ozone-season NO_X (in subparts AAAA through IIII) of the model rules. Commenters generally supported the proposed structure of the model rules, as well as the use of the cap and trade approach, which are maintained in the final rules. Later sections of today's rule discuss specific aspects of the model rules that have been modified or maintained in response to comment.

The EPA designed the model rules to parallel the NO_X SIP Call model trading rules (part 96) and to coordinate with the Acid Rain Program. Mirroring the structure of existing part 96 in the final CAIR NO_X and SO_2 model rules will ease the transition to the CAIR rules as many States and sources are already familiar with the layout of the NO_X SIP Call rule. In addition, because the EPA proposed new CAIR model trading rules—separate from the existing NO_X SIP Call model rule in part 96—States can continue to reference part 96 (subparts A through J) through 2008. The CAIR ozone-season NO_X cap and trade program that the EPA has included in today's final rule is intended for use by CAIR ozone-affected sources as well as those subject to the NO_X SIP Call in 2009 and beyond. Those States that wish to use an EPA-administered, ozone-season cap and trade program to achieve the reductions mandated by the CAIR or the NO_X SIP Call, must use the CAIR ozone-season NO_X model rule (subparts AAAA through IIII) in 2009 and beyond.

The model rules rely on the detailed unit-level emissions monitoring and reporting procedures of part 75 and consistent allowance management practices. (Note that full CAIR-related SIP requirements, *i.e.*, part 51, are discussed in section VII of today's preamble.) Additionally, section IX.B of today's preamble discusses the final revisions to parts 72 through 77 in order to, among other things, facilitate the interaction of the title IV Acid Rain Program's SO_2 cap and trade provisions and those of the CAIR SO_2 trading program.

Road Map of Model Cap and Trade Rules

The following is a brief "road map" to the final CAIR NO_X and SO_2 cap and trade programs. Please refer to the detailed discussions of the CAIR

[122] 40 CFR 51.122 is also amended: (1) to remove a reference to now-obsolete electronic data reporting processes (a "housekeeping" deletion that was specifically included in the proposed rule text with the SNPR), and (2) to make a minor technical correction to properly indicate which of the latitude versus longitude data elements corresponds to the x-coordinate and which to the y-coordinate (a correction that was implicitly proposed in the SNPR in that 51.122 was proposed to refer to 51 subpart A for all its data element descriptions).

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programmatic elements throughout today's rule for further information on each aspect.

State Participation

• States have flexibility to achieve emissions reductions however they chose, including developing and implementing their own trading program.

• States may elect to participate in an EPA-managed cap and trade program. To participate, a State must adopt the model cap and trade rules finalized in this section of today's rule with flexibility to modify sections regarding NO_X allocations and whether to include individual unit opt-in provisions.

• States may participate in EPA-managed cap and trade programs for either the annual NO_X, the ozone-season NO_X, the SO_2, or any combination. The State can only choose to participate in the EPA-administered, CAIR cap and trade program(s) that is (are) relevant to their finding(s).

• The annual NO_X model rule is to be used by only those States that are affected by the CAIR $PM_{2.5}$ finding.

• The ozone-season NO_X model rule is designed to be used by those States that are affected by the CAIR ozone finding as well as take the place of the NO_X SIP Call requirements.[123] The CAIR ozone-season NO_X program will be the only ozone-season NO_X program that EPA will administer. Because EPA will no longer run a NO_X SIP Call trading program, States may include their NO_X SIP Call trading sources if they adopt the EPA-administered CAIR ozone-season NO_X program.

• The SO_2 model rule is designed to satisfy the ongoing statutory requirements of the title IV Acid Rain SO_2 cap and trade program—with sequential compliance with title IV and the CAIR—for sources in the CAIR region that are affected by both the Acid Rain Program and the CAIR.

Trading Sources

• States must achieve all of the mandated emission reductions from EGUs to participate in EPA-managed cap and trade programs. States may include other NO_X SIP Call trading sources in the ozone-season CAIR NO_X cap and trade program and still participate in EPA-managed cap and trade programs.

• States may participate in EPA-managed cap and trade programs whether or not they adopt the optional individual opt-in provisions of the model rule. However, if the State chooses to allow individual sources to opt-in, the opt-in requirements must reflect the requirements of the model rule.

Emission Allowances

• The CAIR annual NO_X cap and trade program will rely upon CAIR annual NO_X allowances allocated by the States. The NO_X SIP Call allowances and CAIR ozone-season NO_X allowances cannot be used for compliance with the annual CAIR reduction requirement. (Note that allowances from the Compliance Supplement Pool (CSP) will be CAIR annual NO_X allowances.)

• The CAIR ozone-season NO_X cap and trade program will rely upon CAIR ozone-season NO_X allowances allocated by the States. In addition, pre-2009 NO_X SIP Call allowances can be banked into the program and used by CAIR-affected sources for compliance with the CAIR ozone-season NO_X program. The NO_X SIP Call allowances of vintages 2009 and later can not be used for compliance with any EPA-administered cap and trade programs.

• The CAIR SO_2 cap and trade program will rely upon title IV SO_2 allowances but may also include additional CAIR SO_2 allowances, should a State that allows an individual unit opt-in mechanism provide CAIR SO_2 allowwances to an opt-in source. Pre-2010 title IV SO_2 allowances can be used for compliance with the CAIR.

• Sulfur dioxide reductions are achieved by requiring sources to retire more than one allowance for each ton of SO_2 emissions. The emission value of an SO_2 allowance is independent of the year in which it is used, but is based upon its vintage (*i.e.*, the year in which the allowance is issued). Sulfur dioxide allowances of vintage 2009 and earlier offset one ton of SO_2 emissions. Vintages 2010 through 2014 offset 0.5 tons of emissions. And, vintages 2015 and beyond offset 0.35 tons of emissions.

Allocation of Allowances to Sources

• For SO_2 allowances, sources have already received allowances through title IV.

• NO_X allowances (for both the annual and ozone-season programs) will be allocated based upon the State's chosen allocation methodology. The EPA's model NO_X rules have provided an example allocation, complete with regulatory text, that may be used by State's or replaced by text that implements a States alternative allocation methodology.

Compliance Supplement Pool (CSP)

• Each State will have a share of the CSP that is comprised of 200,000[124] CAIR annual NO_X allowances of vintage year 2009. The State may distribute the CSP allowances based upon the criteria, found in the SIP Approvability section of today's rule, for early reductions and need.

Emission Monitoring and Reporting by Sources

• Sources monitor and report their emissions using part 75. This includes individual sources that opt-in to the program.

• Source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO_2 and NO_X SIP Call Programs.

• Emission monitoring and reporting for both the CAIR annual and ozone-season NO_X cap and trade programs will use part 75.

Compliance and Penalties

• Compliance for the annual and ozone-season NO_X cap and trade programs, as well as the SO_2 program, will be determined separately.[125]

• For the NO_X and SO_2 cap and trade programs, any source found to have excess emissions must: (1) Surrender allowances sufficient to offset the excess emissions; and, (2) surrender allowances from the next control period equal to three times the excess emissions.

Comments Regarding the Use of a Cap and Trade Approach and the Proposed Structure

Commenters overwhelmingly supported the use of a cap and trade approach and the overall framework of the model rules to achieve the mandated emissions reductions. Some supported the use of cap and trade for achieving regional emissions reductions but noted the need to have additional measures that ensure that emission reductions take place in nonattainment areas. This is in line with the EPA's strategy of reducing transported SO_2 and NO_X through a regionwide cap and trade approach and encouraging States to take complementary measures to address their particular, persistent nonattainment issues. (Note that comments on specific mechanisms

[123] Rhode Island (RI) is the only State currently participating in the NO_X SIP Call cap and trade program that is not affected by today's ozone finding. As is explained in section IX, RI may join the CAIR ozone-season trading program as a means of satisfying its NO_X SIP Call requirements.

[124] The 200,000 total includes the share of the CSP that DE and NJ would receive if the EPA finalizes a parallel rule finding that they are significant contributors for $PM_{2.5}$.

[125] Compliance with the title IV Acid Rain Program will be determined separately from CAIR compliance.

within the cap and trade program are discussed in the topic-specific sections that follow.)

B. What Is the Process for States To Adopt the Model Cap and Trade Programs and How Will It Interact With Existing Programs?

1. Adopting the Model Cap and Trade Programs

States may choose to participate in the EPA-administered cap and trade programs, which are a fully approvable control strategy for achieving all of the emissions reductions required under today's rulemaking in a highly cost-effective manner. States may simply reference the model rules in their State rules and, thereby, comply with the requirements for statewide budget demonstrations detailed in section VII.B of today's preamble. Affected States for both $PM_{2.5}$ and ozone can adopt the annual NO_X and SO_2 cap and trade programs in part 96, subparts AA through II, part 96 subparts AAA through III, and AAAA through IIII. States with ozone-season only CAIR requirements (*i.e.*, Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey) can adopt the ozone-season CAIR NO_X program (subparts AAAA through IIII). Part 96 subparts AA through II and AAA through III can be used by States that are affected for only $PM_{2.5}$ (*i.e.*, Georgia, Minnesota, and Texas). States that elect to achieve the required reductions by regulating other sources or using other approaches will follow alternate State requirements, also described in section VII.B of today's preamble.

As proposed, EPA is requiring States that wish to participate in the EPA-managed cap and trade program to use the model rule to ensure that all participating sources, regardless of which State in the CAIR region they are located, are subject to the same trading and allowance holding requirements. Further, requiring States to use the complete model rule provides for accurate, certain, and consistent quantification of emissions. Because emissions quantification is the basis for applying the emissions authorization provided by each allowance and emissions authorizations (in the form of allowances) are the valuable commodity traded in the market, the emissions quantification requirements of the model rule are necessary to maintain the integrity of the cap and trade approach of the program and therefore, to ensure that the environmental goals of the program are met.

For States Electing To Participate in the EPA-Administered Ozone-Season CAIR NO_X Cap and Trade Program

States that wish to achieve their CAIR ozone-season requirements through an EPA-administered ozone-season NO_X cap and trade program will adopt the CAIR model rule in subparts AAAA through IIII. (Note that the EPA-administered annual NO_X CAIR cap and trade program is independent of ozone-season CAIR NO_X model rule.) Because EPA will no longer administer the trading program for the NO_X SIP Call, States that wish to continue to meet their NO_X SIP Call obligations through an EPA-administered cap and trade program will also adopt the CAIR ozone-season model rule. NO_X SIP Call States will ''sun set'' their NO_X SIP Call rules for sources that will move into the CAIR NO_X ozone-season program. Part 96, sections A–J (*i.e.*, the NO_X SIP Call trading rule) will continue to be available for the NO_X SIP Call and will not be removed for the CAIR. The CAIR model rules specifically address how NO_X SIP Call allowances carry forward into the CAIR NO_X ozone-season program. (Section IX.A provides additional discussion of interactions between the CAIR and the NO_X SIP Call).

For States Electing To Participate in the EPA-Administered Annual NO_X Cap and Trade Program

States that are $PM_{2.5}$ affected and wish to participate in an EPA-administered annual NO_X cap and trade program will adopt the CAIR model rule in subparts AA through II. States may participate by either adopting the model rule provisions by reference or codifying the model rule in their State regulations.

For States Electing To Participate in the EPA-Administered SO_2 Cap and Trade Program

States may simply adopt new provisions, whether by incorporating by reference the CAIR SO_2 cap and Trade rule (part 96, subparts AAA through III) or codifying the provisions of the CAIR SO_2 cap and trade rules, in order to participate in the EPA-administered SO_2 cap and trade program. The CAIR SO_2 model rule works in conjunction with the Acid Rain Program provisions, which are implemented at the Federal level and will stay in place. Today's action also finalizes some revisions to the Acid Rain Program (*i.e.*, parts 72, 73, 74, 75, and 78). (Section IX.B of today's preamble provides additional discussion of interactions between the CAIR and the Acid Rain Program and changes to the Acid Rain Program).

Comments Regarding the Process for Adopting the Model Rules

Commenters supported EPA's proposed process and emphasized the importance of workable model rules, because States with limited resources are likely to incorporate them by reference or heavily rely on them as the basis for State rules.

2. Flexibility in Adopting Model Cap and Trade Rules

It is important to have consistency on a State-to-State basis with the basic requirements of the cap and trade approach when implementing a multi-State cap and trade program. Such consistency ensures the: Preservation of the integrity of the cap and trade approach so that the required emissions reductions are achieved; smooth and efficient operation of the trading market and infrastructure across the multi-State CAIR region so that compliance and administrative costs are minimized; and equitable treatment of owners and operators of regulated sources. However, EPA believes that some limited differences are possible without jeopardizing the environmental and other goals of the program. Therefore, the final rule allows States to modify the model rule language to best suit their unique circumstances in a few, specific areas.

First, States have the flexibility to include, as full trading partners, all trading sources affected by the NO_X SIP Call in the ozone-season CAIR NO_X cap and trade program. This is an outgrowth of the development of the CAIR ozone-season NO_X program, which will be the only ozone-season NO_X cap and trade program administered by EPA.

In addition, States may develop their own NO_X allocations methodologies, provided allocation information is submitted to EPA in the required timeframe. (Section VIII.D of today's preamble discusses unit-level allocations and the related comments in greater detail. This includes a discussion of the provisions establishing the advance notice States must provide for unit-by-unit allocations).

Lastly, States using the model cap and trade rules may elect to include provisions that allow individual units to ''opt-in'' to the cap and trade programs. States that wish to include this mechanism must adopt provisions discussed in section VIII.G of today's rulemaking. Adopting the individual unit opt-in provisions, which would allow non-EGUs that meet the opt-in requirements to enter into the EPA-managed cap and trade programs, does not preclude a State from participating

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in the EPA-administered cap and trade programs.

C. What Sources Are Affected Under the Model Cap and Trade Rules?

In the January 2004 NPR, EPA proposed a method for developing budgets that assumed reductions only from EGUs. Electric Generating Units were defined as: Fossil fuel-fired, non-cogeneration EGUs serving a generator with a nameplate capacity of greater than 25 MWe; and fossil fuel-fired cogeneration EGUs meeting certain criteria (referred to as the ''1/3 potential electric output capacity criteria''). In the SNPR, we proposed model cap and trade rules that applied to the same categories of sources. We are finalizing the nameplate capacity cut-off that we proposed in the NPR for developing budgets and that we proposed in the SNPR for the applicability of the model trading rules. We are also finalizing the ''fossil fuel-fired'' definition and the 1/3 electric output capacity criteria that were proposed. The actual rule language in the SNPR describing the sources to which the model rules apply is being slightly revised to be clearer in response to some comments that the proposed language was not clear.

1. 25 MW Cut-Off

The EPA is retaining the 25 MW cut-off for EGUs for budget and model rule purposes. The EPA believes it is reasonable to assume no further control of air emissions from smaller EGUs. Available air emissions data indicate that the collective emissions from small EGUs are relatively small and that further regulating their emissions would be burdensome, to both the regulated community and regulators, given the relatively large number of such units. For example, NO_X and SO_2 emissions from EGUs of 25 MW or less in the CAIR region represent approximately one percent and two percent of total NO_X and SO_2 emissions from EGUs, respectively. There are over 4000 EGUs of 25 MW or less in the CAIR region. Consequently, EPA believes that administrative actions to control this large group with small emissions would be inordinate and thus does not believe these small units should be included. This approach of using a 25 MW cut-off for EGUs is consistent with existing SO_2 and NO_X cap and trade programs such as the NO_X SIP Call (where existing and new EGUs at or under this cut-off are, for similar reasons, not required to be included) and the Acid Rain Program (where this cut-off is applied to existing units and to new units combusting clean fuel). Also, EPA's New Source Performance Standards use an applicability threshold of approximately 25 MW under subpart Da.

One commenter suggested a plant-wide cut-off of 250 MW. This commenter suggested that including units between 25 and 250 MW would cause these units to shutdown but failed to provide any analysis to support its claim. Such a cut-off would be inconsistent with other existing SO_2 and NO_X cap and trade programs as noted above. The EPA estimates that approximately 1/3 of the SO_2 reductions, and 30 percent of the NO_X reductions, required under today's rule come from plants between 25 MW and 250 MW. Our modeling shows that some units below 250 MW will put on controls as part of our highly cost-effective set of control actions. The units also have the option to coal-switch, alter dispatch, and/or purchase allowances.

Another commenter suggested that, in lieu of the language proposed in the SNPR, EPA adopt a definition for EGU that, according to the commenter, is the Acid Rain Program's definition of affected utility. The commenter stated that the Acid Rain definition of EGU is ''all fossil fuel-fired units with a nameplate capacity greater than 25 MW supplying more than 1/3 of potential electrical output to the grid.'' However, the commenter misstated the Acid Rain definition and confused the Acid Rain applicability provisions concerning utility units in general with those provisions concerning cogeneration units in particular. The Acid Rain Program covers, with certain exceptions,[126] all existing fossil fuel-fired units greater than 25 MW that produce any electricity for sale; and new fossil fuel-fired units that produce any electricity for sale. The language referenced by the commenter concerning potential electrical output applies, in the Acid Rain Program, only to cogeneration units, not all fossil fuel-fired units. For non-cogeneration units, there is no exemption from Acid Rain Program requirements based on the unit selling a ''small'' amount of electricity for sale. The provisions in the NPR and the SNPR concerning cogeneration units are discussed below.

2. Definition of Fossil Fuel-Fired The

EPA is finalizing the proposed definition of fossil fuel-fired, *i.e.*, where any amount of fossil fuel is used at any time. This is the same definition that is used in the Acid Rain Program. One commenter suggested that the proposed definition is too broad and that EPA should use in the CAIR Program the same definition that is used in the NO_X SIP Call, *i.e.*, where a unit uses fossil fuel for at least 50 percent of its annual heat input during a specified period. The same commenter also proposed excluding large wood-fired boilers and black liquor recovery furnaces. The commenter's definition would result in units already subject to the Acid Rain Program in a given State being excluded from the CAIR Program and the model cap and trade rules applicable in that State. Such exclusion would make it more difficult to coordinate the Acid Rain Program and the CAIR Program. Consequently, EPA rejects the commenter's more restricted definition of fossil fuel-fired.

The EPA recognizes that new (*i.e.*, post-1990) units that are 25 MW or less and burn other than clean fuels are subject to the Acid Rain Program but not to the CAIR Program. However, there are very few such units, and EPA has decided to exclude any units that are 25 MW or less on other grounds discussed above.

3. Exemption for Cogeneration Units

As proposed, EPA is finalizing an exemption from the model cap and trade programs for cogeneration units, *i.e.*, units having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through sequential use of energy and meeting certain operating and efficiency standards (discussed below). The EPA is adopting the proposed definition of cogeneration unit and the proposed criteria for determining which cogeneration units qualify for the exemption from the model cap and trade programs.

The CAIR trading program has different applicability provisions for non-cogeneration units and cogeneration units. If a unit initially qualifies as a cogeneration unit, and for the exemption from the trading program for certain cogeneration units, but subsequently loses its cogeneration-unit status (*e.g.*, due to changes in operation), such unit loses the cogeneration-unit exemption and becomes subject to the applicability criteria for non-cogeneration units, regardless of any future changes in the unit or its operations. If, under the non-cogeneration unit applicability criteria, the unit becomes subject to the trading program, the unit will remain subject to the program in the future. Conversely if a unit initially does not qualify as a cogeneration unit, such unit becomes subject to the applicability criteria for non-cogeneration units, regardless of

[126] For example, certain cogeneration units and new units 25 MW or less that burn only clean fuel are exempt from the Acid Rain Program.

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any future changes in the unit. If, under such criteria, the unit is subject to the trading program, the unit will remain subject to the program in the future. This approach to applicability means that units (other than, in some cases, opt-in units) cannot go in and out of the trading program, which, if allowed, would make it difficult for EPA, States, and owners or operators to determine which units should be complying with trading program requirements, and during what years, and would likely result in more non-compliance problems.

a. Efficiency Standard for Cogeneration Units

The EPA proposed operating and efficiency standards (*i.e.*, the useful thermal energy output of the unit must be no less than a certain percent of the total energy output and, in some cases, useful power must be no less than a certain percent of total energy input) in the SNPR that a unit must meet in order to qualify as a cogeneration unit. If the unit qualifies as a cogeneration unit, then it may be eligible for exemption from the CAIR, depending upon whether it meets additional operating criteria, discussed below. As discussed in the NPR, EPA proposed the same operating and efficiency standards for all fossil fuel-fired units (regardless of whether they burn coal, oil, or gas). In addition, not applying the operating and efficiency standards to coal-fired units would be counter productive to EPA's efforts to reduce SO_2 and NO_X emissions under this proposed rule because of the relatively high SO_2 and NO_X emissions from coal-fired units. In particular, without application of the efficiency standards to coal-fired units, highly inefficient coal-fired units, which have particularly high emissions per MWhr generated, could be exempt from the CAIR Program. In addition, if coal-fired units were not subject to the operating standard, the potential would exist for a coal-fired unit to provide only a token amount of useful thermal energy and still qualify for a cogeneration unit exemption from the CAIR Program, despite having relatively high emissions.

One commenter suggested that EPA should not use the efficiency standards for solid fuel-fired cogeneration units, because it may require some coal-fired cogeneration units that were exempt from the Acid Rain Program to purchase CAIR allowances. However, the EPA analysis indicates that most existing solid fuel-fired cogeneration units affected by this rule will meet the proposed standard. See TSD entitled "Cogeneration Unit Efficiency Calculations" in the docket. To the extent any solid fuel-fired cogeneration units cannot meet the efficiency standard and become affected units under the CAIR, EPA believes that, considering their relatively high emissions of SO_2 and NO_X compared to oil and gas-fired units, it is important to require these sources to meet the efficiency standards or be subject to the emission limits under the CAIR Program.

Another commenter suggested that the efficiency standards should not apply to solid fuel-fired cogeneration units because solid fuel-fired unit efficiency is based on HHV (higher heating value) while gas, or oil-fired unit efficiency is based on LHV (lower heating value). The EPA analyzed a range[127] of solid fuel-fired cogeneration units and calculated their efficiencies to see if they would meet the minimum efficiency standard. All of the units selected satisfied the proposed efficiency standard. See TSD entitled "Cogeneration Unit Efficiency Calculations" in the docket. As a result, EPA believes that most solid fuel-fired cogeneration units will meet the proposed efficiency standard. The efficiency standard EPA is adopting is the Public Utility Regulatory Act (PURPA) of thermal efficiency of 42.5 percent. See TSD entitled, "Cogeneration Unit Efficiency Calculations" for further discussion, is based on LHV. If the efficiency of a solid-fuel-fired unit is expressed in terms of HHV, it can easily be converted to LHV for purposes of determining whether it meets the efficiency standard. Therefore, the reason given by the commenter (that solid fuel-fired unit efficiency is expressed in terms of HHV) is not grounds for not applying an efficiency standard to these units. One commenter supported applying the same efficiency standard to solid fuel-fired units as EPA proposed. The EPA is finalizing its proposed cogeneration unit definition, which applies the same operating and efficiency standards to all units regardless of the type of fossil fuel burned.

b. One-third Potential Electric Output Capacity

The EPA is finalizing the $^1/_3$ potential electric output capacity criteria in the NPR and SNPR. Under the proposals, the following cogeneration units are EGUs: Any cogeneration unit serving a generator with a nameplate capacity of greater than 25 MW and supplying more than $^1/_3$ potential electric output capacity and more than 219,000 MW-hrs annually to any utility power distribution system for sale. These criteria are similar to those used in the Acid Rain Program to determine whether a cogeneration unit is a utility unit and the NO_X SIP Call to determine whether a cogeneration unit is an EGU or a non-EGU. The primary difference between the proposed criteria and the $^1/_3$ potential electric criteria for the Acid Rain and NO_X SIP Call Programs is that these programs applied the criteria to the initial operation of the unit and then to 3-year rolling average periods while the proposed CAIR criteria are applied to each individual year starting with the commencement of operation. The EPA believes that using an individual year approach would streamline the application and administration of this exemption. No adverse comments were received on using an individual year approach as opposed to a 3-year rolling average. In addition, the criteria under the Acid Rain Program and the NO_X SIP Call are applied somewhat differently to units commencing construction on or before November 15, 1990 and units commencing construction after November 15, 1990. Several commenters suggested exempting all cogeneration units under the PURPA instead of using the proposed criteria and cite the high efficiency of cogeneration as a reason for a complete exemption. The EPA believes it is important to include in the CAIR Program all units, including cogeneration units, that are substantially in the business of selling electricity. The proposed $^1/_3$ potential electric output criteria described above are intended to do that.

Inclusion of all units substantially in the electricity sales business minimizes the potential for shifting utilization, and emissions, from regulated to unregulated units in that business and thereby freeing up allowances, with the result that total emissions from generation of electricity for sale exceed the CAIR emissions caps. The fact that units in the electricity sales business are generally interconnected through their access to the grid significantly increases the potential for utilization shifting.

One commenter suggested that the $^1/_3$ of potential electric output capacity criteria be applied on an annual basis. The EPA agrees that the criteria should be applied annually. The proposed and final model cap and trade rules adopt that approach.

c. Clarifying "For Sale"

Several commenters requested EPA confirm that, for purposes of applying the $^1/_3$ potential electric output criteria,

[127] The range included solid fuel-fired cogeneration units from 25 MW to 250 MW.

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simultaneous purchases and sales of electricity are to be measured on a ''net'' basis, as is done in the Acid Rain Program. At least one commenter suggested that the net approach also be applied to purchase and sales that are not simultaneous. For purposes of applying the $^1/_3$ potential electric output criteria in the CAIR Program and the model cap and trade rules, EPA confirms that the only electricity that counts as a sale is electricity produced by a unit that actually flows to a utility power distribution system from the unit. Electricity that is produced by the unit and used on-site by the electricity-consuming component of the facility will not count, including cogenerated electricity that is simultaneously purchased by the utility and sold back to such facility under purchase and sale agreements under the PURPA. However, electric purchases and sales that are not simultaneous will not be netted; the $^1/_3$ potential electric output criteria will be applied on a gross basis, except for simultaneous purchase and sales. This is consistent with the approach taken in the Acid Rain Program.

d. Multiple Cogeneration Units

Some commenters suggested aggregating multiple cogeneration units that are connected to a utility distribution system through a single point when applying the $^1/_3$ potential electric output capacity criteria. These commenters suggested that it is not feasible to determine which unit is producing the electricity exported to the outside grid. The EPA proposed to determine whether a unit is affected by the CAIR on an individual-unit basis. This unit-based approach is consistent with both the Acid Rain Program and the NO_X SIP Call. The EPA considers this approach to be feasible based on experience from these existing programs, including for sources with multiple cogeneration units. The EPA is unaware of any instances of cogeneration unit owners being unable to determine how to apply the $^1/_3$ potential electric output capacity criteria where there are multiple cogeneration units at a source.

In a case where there are multiple cogeneration units with only one connection to a utility power distribution system, the electricity supplied to the utility distribution system can be apportioned among the units in order to apply the $^1/_3$ potential electric output capacity criteria. A reasonable basis for such apportionment must be developed based on the particular circumstances. The most accurate way of apportioning the electricity supplied to the utility power distribution system seems to be apportionment based on the amount of electricity produced by each unit during the relevant period of time.

Exemption for Independent Power Production (IPP) Facilities: Some commenters stated that certain IPP facilities are exempt from the Acid Rain Program and that they should also be exempt from the CAIR Program and model-cap and trade rules. Under the Acid Rain Program, an IPP facility that has, as of November 15, 1990, a qualifying power purchase commitment (including a sales price) to sell at least 15 percent of planned net output capacity and has installed net output capacity not exceeding 130 percent of planned net output capacity is exempt. However, if the power purchase commitment changes after November 15, 1990 in a way that allows the cost of compliance with the Acid Rain Program to be shifted to the purchaser, then the IPP facility loses the exemption. For example, expiration or termination of the power purchase commitment or modification so that the price is increased (*e.g.*, changed to a market price) results in loss of the exemption. The purpose of the exemption is to protect IPP facilities subject to contract prices that were set before passage of the CAA Amendments of 1990 (including the Acid Rain Program in title IV) and that did not allow passthrough of the costs of Acid Rain Program compliance. However, EPA maintains that this exemption was aimed at easing the transition of such facilities into the Acid Rain Program and that there is no basis for maintaining this exemption for every subsequent cap and trade program. In addition, this exemption was not used in the NO_X SIP Call.

D. How Are Emission Allowances Allocated to Sources?

It is important to have consistency on a State-by-State basis with the basic requirements of the cap and trade approach when implementing a multi-State cap and trade program. This will ensure that: The integrity of the cap and trade approach is preserved so that the required emissions reductions are achieved; the compliance and administrative costs are minimized; and source owners and operators are equitably treated. However, EPA believes that some limited differences, such as allowance allocation methodologies for NO_X allowances, are possible without jeopardizing the environmental and other goals of the program.

1. Allocation of NO_X and SO_2 Allowances

Each State participating in EPA-administered cap and trade programs must develop a method for allocating (*i.e.*, distributing) an amount of allowances authorizing the emissions tonnage of the State's CAIR EGU budget. For NO_X allowances, each State has the flexibility to allocate its allowances however they choose, so long as certain timing requirements are met.

For SO_2, as noted in the January 2004 proposal, States will have no discretion in their allocation approach since the CAIR SO_2 cap and trade program uses title IV SO_2 allowances, which have been already allocated in perpetuity to individual units by title IV of the CAA.

a. Required Aspects of a State NO_X Allocation Approach

While it is EPA's intent to provide States with as much flexibility as possible in developing allocation approaches, there are some aspects of State allocations that must be consistent for all States. All State allocation systems are required to include specific provisions that establish when States notify EPA and sources of the unit-by-unit allocations. These provisions establish a deadline for each State to submit to EPA its unit-by-unit allocations for processing into the electronic allowance tracking system. Since the Administrator will then expeditiously record the submitted allowance allocations, sources will thereby be notified of, and have access to, allocations with a minimum lead time (about 3 years) before the allowances can be used to meet the NO_X emission limit.

Today's action finalizes the proposal to require States to submit unit-by-unit allocations of allowances for a given year no less than 3 years prior to January 1 of the allowance vintage year, which approach was supported by commenters.[128] Requiring States to submit allocations and thereby provide a minimum lead time before the allowances can be used to meet the NO_X emission limit ensures that an affected source—regardless of the State in the CAIR region in which the unit is located—will have sufficient time to plan for compliance and implement their compliance planning. Allocating allowances less than 3 years in advance of the compliance year may reduce a CAIR unit's ability to plan for and implement compliance and,

[128] If the deadline for States to submit SIPs is September of 2006, then this would result in notification period of less than 3 years for the first year of CAIR.

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consequently, increase compliance costs. For example, a shorter lead time would reduce the period for buying or selling allowances and could prevent sources from participating in allowance futures markets, a mechanism for hedging risk and lowering costs.

Further, requiring a uniform, minimum lead-time for submission of allocations allows EPA to perform its allocation-recordation activities in a coordinated and efficient manner in order to complete expeditiously the recordation for the entire CAIR region and thereby promote a fair and competitive allowance market across the region.

These minimum requirements apply to the NO_X allocation approach and are not relevant for the SO_2 cap and trade program, which relies on title IV allowances.

b. Flexibility and Options for a State NO_X Allowance Allocations Approach

Allowance allocation decisions in a cap-and-trade program raise essentially distributional issues, as economic forces are expected to result in economically efficient and environmentally similar outcomes regardless of the manner in which allowances are initially distributed. Consequently, for CAIR NO_X allowances, States are given latitude in developing their allocation approach. NO_X allocation methodology elements for which States will have flexibility include:

A. The cost of the allowance distribution (*e.g.*, free distribution or auction);

B. The frequency of allocations (*e.g.*, permanent or periodically updated);

C. The basis for distributing the allowances (*e.g.*, heat-input or power output); and,

D. The use of allowance set-asides and their size, if used (*e.g.*, new unit set-asides or set-asides for energy efficiency, for development of Integrated Gasification Combined Cycle (IGCC) generation, for renewables, or for small units).

Some commenters have argued against giving States flexibility in determining NO_X allocations, citing concerns about complexity of operating in different markets and about the robustness of the trading system. The EPA maintains that offering such flexibility, as it did in the NO_X SIP Call, does not compromise the effectiveness of the trading program.

A number of commenters have argued against allowing (or requiring) the use of allowance auctions, while others did not believe that EPA should recommend auctions. For today's final action, while there are some clear potential benefits to using auctions for allocating allowances (as noted in the SNPR), EPA believes that the decision regarding utilizing auctions should ultimately be made by the States. Therefore, EPA is not requiring, restricting, or barring State use of auctions for allocating allowances.

A number of commenters supported allowing the use of allowance set-asides for various purposes. In today's final action, EPA is leaving the decision on using set-asides up to the States, so that States may craft their allocation approach to meet their State-specific policy goals.

i. Example Allowance Allocation Methodology

In the SNPR, EPA included an example (offered for informational guidance) of an allocation methodology that includes allowances for new generation and is administratively straightforward. In today's preamble, EPA is including in today's preamble, this ''modified output'' example allocations approach, as was outlined in the SNPR.

The EPA maintains that the choice of allocation methodology does not impact the achievement of the specific environmental goals of the CAIR Program. This methodology is offered simply as an example, and individual States retain full latitude to make their own choices regarding what type of allocation method to adopt for NO_X allowances and are not bound in any way to adopt EPA's example.

This example method involves input-based allocations for existing fossil units, with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating. Providing allowances for new sources addresses a number of commenter concerns about the negative effect of new units not having access to allowances.

Under the example method, allocations are made from the State's EGU NO_X budget for the first five control periods (2009 through 2013) of the model cap and trade program for existing sources on the basis of historic baseline heat input. Commenters expressed some concern regarding the proposed January 1, 1998 cut-off on-line date for considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least 5 years of operating data, *i.e.*, data for 1998 through 2002 (which was the last year for which annual data was available). The EPA is still concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. The EPA believes that a 5 year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations. Annual operating data is now available for 2003. The EPA is finalizing January 1, 2001 as the cut-off on-line date for considering units as existing units since units meeting the cut-off date will have at least 5 years of operating data (*i.e.*, data for 2001 through 2005).

The allowances for 2014 and later will be allocated from the State's EGU NO_X budget annually, 6 years in advance, taking into account output data from new units with established baselines (modified by the heat input conversion factor to yield heat input numbers). As new units enter into service and establish a baseline, they are allocated allowances in proportion to their share of the total calculated heat input (which is existing unit heat input plus new units' modified output). Allowances allocated to existing units slowly decline as their share of total calculated heat input decreases with the entry of new units.

After 5 years of operation, a new unit will have an adequate operating baseline of output data to be incorporated into the calculations for allocations to all affected units. The average of the highest 3 years from these 5 years will be multiplied by the heat-input conversion factor to calculate the heat input value that will be used to determine the new unit's allocation from the pool of allowances for all sources.

Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement since it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowances allocations.

Moreover, new units as a group will only update their heat input numbers once—for the initial 5-year baseline period after they start operating. This will eliminate any potential generation subsidy and be easier to implement, since it will not require the collection

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and processing of data needed for regular updating.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. The EPA expects that any problems with standardizing and collecting output data, to the extent that they exist, can be resolved in time for their use for new unit calculations. Given that units keep track of electricity output for commercial purposes, this is not likely to be a significant problem.

A number of commenters expressed support for EPA's proposal in the SNPR that the heat input data for existing units be adjusted by multiplying it by different factors based on fuel-type. Contrary to some commenters' claims, determining allocations with fuel factors would not create disincentives for efficiency. With the use of a single baseline for existing units, neither adjusted input, nor input, nor output based allocations would provide additional incentives for energy efficiency. All sources have incentives to reduce emissions (improving efficiency is a way of doing this) as a result of the cap and trade program, not because of the choice of an allocation based on a single historic baseline.

The EPA acknowledges that since allowances have value, different allocations of allowances clearly do impact the distribution of wealth among different generators. However, in general, the economics of power generation dictate that generators selling power will seek to operate (and burn fuel) to meet energy demand in a least-cost manner. The cost of the power generated (reflecting the bid price per megawatt hour) will include the cost of allowances to cover emissions, whether the generator uses allowances that it already owns, or whether it needs to purchase additional allowances. With a liquid market for allowances, allocations for existing sources (whose baseline does not change) are a sunk benefit or sunk cost, not impacting the existing generator's behavior on the margin. Thus, the use of fuel factors in our allocating method would not be expected to result in changes in generators' choices for fuel efficiency.

In its example allocation approach, EPA is including adjustments of heat input by fuel type based on average historic NO_X emissions rates by three fuel types (coal, natural gas, and oil) for the years 1999–2002. As noted in the SNPR, such calculations would lead to adjustment factors of 1.0 for coal, 0.4 for gas and 0.6 for oil. The factors would reflect the inherently different emissions rates of different fossil-fired units (and consequently also reflect the different burdens to control emissions.

However, allocating to new (not existing) sources on the basis of input (and particularly fuel-adjusted heat input) would serve to subsidize less-efficient new generation. For a given amount of generation, more efficient units will have the lower fuel input or heat input. Allocating to new units based on heat input could encourage the building of less efficient units since they would get more allowances than an equivalent efficient, lower heat-input unit. The modified output approach, as described below, will encourage new, clean generation, and will not reward less efficient new coal units or less efficient new gas units.

Under the example method, allowances will be allocated to new units of each fuel-type with an appropriate baseline on a ''modified output'' basis. The new unit's modified output will be calculated by multiplying its gross output by a heat rate conversion factor of 7,900 btu/kWh for coal units and 6,675 btu/kWh for oil and gas units. The 7,900 btu/kWh value for the conversion factor for new coal units is an average of heat-rates for new pulverized coal plants and new IGCC coal plants (based upon assumptions in EIA's Annual Energy Outlook (AEO) 2004 [129]). The 6,675 btu/kWh value for the conversion factor for new gas units is an average of heat-rates for new combined cycle gas units (also based upon assumptions in EIA's AEO 2004). A single conversion rate for each fuel-type will create consistent and level incentives for efficient generation, rather than favoring new units with higher heat-rates.

For new cogeneration units, their share of the allowances will be calculated by converting the available thermal output (btu) of useable steam from a boiler or useable heat from a heat exchanger to an equivalent heat input by dividing the total thermal output (btu) by a general boiler/heat exchanger efficiency of 80 percent.

New combustion turbine cogeneration units will calculate their share of allowances by first converting the available thermal output of useable steam from a heat recovery steam generator (HRSG) or useable heat from a heat exchanger to an equivalent heat input by dividing the total thermal output (btu) by the general boiler/heat exchanger efficiency of 80 percent. To this they will add the electrical generation from the combustion turbine, converted to an equivalent heat input by multiplying by the conversion factor of 3,413 btu/kWh. This sum will yield the total equivalent heat input for the cogeneration unit.

Steam and heat output, like electrical output, is a useable form of energy that can be utilized to power other processes. Because it would be nearly impossible to adequately define the efficiency in converting steam energy into the final product for all of the various processes, this approach focuses on the efficiency of a cogeneration unit in capturing energy in the form of steam or heat from the fuel input.

Commenters expressed concern about a single conversion factor, arguing for different factors for different fuels and technologies. The EPA recognizes these concerns and agrees that different new fossil-generation units have inherently different heat rates, largely dictated by the technology needed to burn different fuels. A single conversion rate for all units would provide new gas-fired combined cycle units with relatively more allowances, relative to their emissions, than it would for new coal-fired units.

The EPA maintains that providing each new source an equal amount of allowances per MWh of output, given the fuel it is burning, is an equitable approach. Since electricity output is the ultimate product being produced by EGUs, a single conversion factor for each fuel, based on output, ensures that all new sources burning a particular fuel will be treated equally.

Some commenters support allocating allowances to all new generation, not just fossil fuel-fired CAIR units. The EPA notes that including new non-CAIR and non-fossil units in the allowance distribution would raise issues, about which EPA lacks sufficient information for resolution at this time for EPA's example method. It would be necessary to clearly define what types of generating facilities that could participate and what would constitute ''new'' non-fossil generation.[130] Commenters did not provide any analysis of the impact of possible definitions on generation mix, or electricity markets. Further, in order to include all generation, there would be a need to establish application and data

[129] Energy Information Administration, ''Annual Energy Outlook 2004, With Projections to 2025'', January 2004. Assumptions for the NEMS model. *http://www.eia.doe.gov/oiaf/archive/aeo04/assumption/tbl38.html.*

[130] Some commenters stated that, if allocations were provided for non-emitting new generation, they also should be provided to all such generation, including nuclear units.

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collections procedures and determine appropriate size cut-offs and boundaries of this generation—since in many such instances there is no clear analog to discrete fossil ''units.'' [131] There also are associated issues about developing appropriate measurement and data reporting requirements for such sources. Commenters supporting this approach did not address any of these matters in any detail. However, EPA encourages States that are interested in including such units in their updating allocations to consider potential solutions and include them in their SIPs. Under the example method, new units that have entered service, but have not yet started receiving allowances through the update, will receive allowances each year from a new source set-aside. The new source allowances from the set-aside will be distributed based on their actual emissions from the previous year. Such an allocation approach will generally provide new units sufficient allowances to cover their emissions during the interim period before the units are allocated allowances on the same basis as existing units.

Today's example method includes a new source set-aside equal to 5 percent of the State's emission budget for the years 2009–2013 and 3 percent of the State's emission budget for the subsequent years. In the SNPR, EPA proposed a level 2 percent set-aside for all years.

Commenters noted their concern that the amount of the set-aside in the early years of the program should be higher to reflect the fact that the set-aside will initially need to accommodate all new units entering into service from 1998 through 2010.[132] In order to estimate the need for allocations for new units, EPA looked at the NO_X emissions from units that went online starting in 1999 as projected by the Integrated Planning Model (IPM) runs modeling CAIR for the years 2010 and 2015. These IPM emissions projections indicated over 57,000 tons of NO_X emissions in 2010 and about 74,000 tons of NO_X emission by 2015 from new sources need to be covered under set-asides throughout the CAIR region. The 2010 number represents almost 4 percent of the Phase I NO_X regional cap, while the 2015 number represents about 6 percent of the Phase I regional cap. Consequently, today's example method includes a 5 percent set-aside for the initial period (2009–2013). It should be noted that by 2014, the set-aside would need to cover new sources from the entire period 2004–2013.

The choice of a 3 percent new source set-aside, starting in 2014, reflects concerns that adequate allowances be provided for the 10 years of new units to be covered by the set-aside in 2014 and subsequent years. (The set-aside in 2014, for example, would need to accommodate all units that went on-line between 2004 and 2013).

Individual States using a version of the example method may want to adjust this initial 5 year set-aside amount to a number higher or lower than 5 percent to the extent that they expect to have more or less new generation going on-line during the 2001–2013 period. They may also want to adjust the subsequent set-aside amount to a number higher or lower than 3 percent to the extent that they expect more or less new generation going on-line after 2004. States may also want to set this percentage a little higher than the expected need, since, in the event that the amount of the set-aside exceeds the need for new unit allowances, the State may want to provide that any unused set-aside allowances will be redistributed to existing units in proportion to their existing allocations.

For the example method, EPA is finalizing the approach that new units will begin receiving allowances from the set-aside for the control period immediately following the control period in which the new unit commences commercial operation, based on the unit's emissions for the preceding control period. Thus, a source will be required to hold allowances during its start-up year, but will not receive an allocation for that year.

States will allocate allowances from the set-aside to all new units in any given year as a group. If there are more allowances requested than in the set-aside, allowances will be distributed on a pro-rata basis. Allowance allocations for a given new unit in following years will continue to be based on the prior year's emissions until the new unit establishes a baseline, is treated as an existing unit, and is allocated allowances through the State's updating process. This will enable new units to have a good sense of the amount of allowances they will likely receive—in proportion to their emissions for the previous year. This methodology will not provide allowances to a unit in its first year of operation; however it is a methodology that is straightforward, reasonable to implement, and predictable.

In the SNPR, the example method from the NO_X SIP Call model rule was proposed as an alternate approach.[133] However, the EPA has found this approach to be complicated for both the States and the EPA to implement. Additionally, the NO_X SIP Call approach would introduce a higher level of uncertainty for sources in the allocation process than necessary.

While the EPA is offering an example allocation method with accompanying regulatory language, the EPA reiterates that it is giving States' flexibility in choosing their NO_X allocations method so they may tailor it to their unique circumstances and interests. Several commenters, for instance, have noted their desire for full output-based allocations (in contrast to the hybrid approach in the example above). In the past, EPA had sponsored a work group to assist States wishing to adopt output-based NO_X allocations for the NO_X SIP Call and believes it is a viable approach worth considering. Documents from meetings of this group and the resulting guidance report (found at *http://www.epa.gov/airmarkets/fednox/workgrp.html)* together with additional resources such as the EPA-sponsored report ''Output-Based Regulations: A Handbook for Air Regulators'' (found at *http://www.epa.gov/cleanenergy/pdf/output_rpt.pdf*) can help States, should they choose to adopt any output-based elements in their allocation plans.

As an another alternative example, States could decide to include elements of auctions into their allowance allocation programs.[134] An example of an approach where CAIR NO_X allowances could be distributed to sources through a combination of an auction and a free allocation is provided below.

During the first year of the trading program, 94 percent of the NO_X allowances could, for example, be allocated to affected units with an auction held for the remaining 1 percent of the NO_X allowances [135]. Each subsequent year, an additional 1 percent of the allowances (for the first 20 years of the program), and then an additional 2.5 percent thereafter, could be auctioned until eventually all the allowances are auctioned. With such a system, for the first 20 years of the

[131] For instance, would the addition of a single new wind turbine at a wind-farm constitute a ''new unit''?

[132] As noted earlier in this section, EPA is now considering new units to be those that went online after January 1, 2001 rather than 1998.

[133] With the alternate approach from the NO_X SIP Call. States could distribute a new source set-aside for a control period based on full utilization rates, at the end of the year the actual allowance allocation would be adjusted to account for actual unit utilization/output, and excess allowances would be returned and redistributed, first taking into account new unit requests that were not able to be addressed.

[134] Auctions could provide States with a non-distortionary source of revenue.

[135] 5 percent of the allowances would go to a new source set-aside.

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trading programs, the majority of allowances would be distributed for free via the allocation. Allowances allocated for these earlier years are generally more valuable than allowances allocated for later years because of the time value of money. Thus, most emitting units would receive relatively more allowances in the early years of the program, when they are facing the expenses of taking actions to control their emissions. Even though the proportion of allowances allocated to existing sources declines in the later years of the program, these sources receive for free a very significant share of the total value of allowances (because the discounted present value of allowances allocated in the early years of the program is greater than the discounted present value of the allowances auctioned later).

Auctions could be designed by the State to promote an efficient distribution of allowances and a competitive market. Allowances would be offered for sale before or during the year for which such allowances may be used to meet the requirement to hold allowances. States would decide on the frequency and timing of auctions. Each auction would be open to any person, who would submit bids according to auction procedures, a bidding schedule, a bidding means, and by fulfilling requirements for financial guarantees as specified by the State. Winning bids, and required payments, for allowances would be determined in accordance with the State program and ownership of allowances would be recorded in the EPA Allowance Tracking System after the required payment is received.

The auction could be a multiple-round auction. Interested bidders would submit before the auction, one or more initial bids to purchase a specified quantity of NO_X allowances at a reserve price specified by the State, specifying the appropriate account in the Allowance Tracking System in which such allowances would be recorded. Each bid would be guaranteed by a certified check, a funds transfer, or, in a form acceptable to the State, a letter of credit for such quantity multiplied by the reserve price. For each round of the auction, the State would announce current round reserve prices for NO_X and determine whether the sum of the acceptable bids exceeds the quantity of such allowances, available for auction. If the sum of the acceptable bids for NO_X allowances exceeds the quantity of such allowances the State would increase the reserve price for the next round. After the auction, the State would publish the names of winning and losing bidders, their quantities awarded, and the final prices. The State would return payment to unsuccessful bidders and add any unsold allowances to the next relevant auction.

In summary, today's action provides, for States participating in the EPA-administered CAIR NO_X cap and trade program, the flexibility to determine their own methods for allocating NO_X allowances to their sources. Specifically, such States will have flexibility concerning the cost of the allowance distribution, the frequency of allocations, the basis for distributing the allowances, and the use and size of allowance set-asides.

E. What Mechanisms Affect the Trading of Emission Allowances?

1. Banking

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

Banking is the retention of unused allowances from 1 calendar year for use in a later calendar year. Banking allows sources to make reductions beyond required levels and ''bank'' the unused allowances for use later. Generally speaking, banking has several advantages: It can encourage earlier or greater reductions than are required from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reductions goals. When sources reduce their SO_2 and NO_X emissions in the early phases, the cap and trade program creates an emissions ''glide path'' that provides earlier environmental benefits and lower cost of compliance. This ''glide path'' does allow emissions to exceed the cap and trade program budget—especially in the initial years after the adoption of a more stringent cap. The use of banked allowances from the Acid Rain and NO_X SIP Call Programs in the CAIR NO_X and SO_2 cap and trade programs is discussed below in section VIII.F of this preamble.

The January 30, 2004 CAIR NPR and June 10, 2004 CAIR SNPR proposed that the CAIR NO_X and SO_2 cap and trade programs allow banking and the use of banked allowances without restrictions. Allowing unrestricted banking and the use of banked allowances is consistent with the existing Acid Rain SO_2 cap and trade program. The NO_X SIP Call cap and trade program, however, has some restrictions on the use of banked allowances, a procedure called ''flow control,'' described in detail in the June 10, 2004 CAIR SNPR.

Comments Regarding Unrestricted Banking After the Start of the CAIR NO_X and SO_2 Cap and Trade Programs

Many commenters supported the EPA's proposal to allow unrestricted banking and the use of banked allowances for both SO_2 and NO_X, agreeing that flow control is a complex and confusing procedure with undemonstrated environmental benefit. Further, they agreed that banking with no restrictions on use will encourage early emissions reductions, stimulate the trading market, encourage efficient pollution control, and provide flexibility to affected sources in meeting environmental objectives.

Other commenters objected to the EPA's proposal to allow unrestricted use of banked allowances. All of these commenters supported some use of flow control in the CAIR cap and trade programs, most supporting its use for both SO_2 and NO_X.

Some commenters disagreed with the EPA's assessment that the use of flow control in the Ozone Transport Commission (OTC) cap and trade program was complicated to understand and implement and caused market complexity. One commenter further elaborated that flow control was accepted by industry. Another commenter claimed that the EPA has not analyzed the impact of the flow control mechanism.

Some commenters supportive of flow control stated that flow control was ''successful'' in the OTC and NO_X SIP Call trading programs and ''worked well'' and ''achieved the desired effect,'' without supporting those statements.

b. The Final CAIR Model Rules and Banking

The EPA acknowledges that the OTC NO_X cap and trade program has functioned for several years despite the complexity introduced by the flow control procedures. Industry and other allowance traders have adapted to these complex procedures, yet there are ongoing questions from the regulated community about how the procedures actually work. As an example, one commenter, while disagreeing with the EPA's assertion that flow control is overly complex, goes on to describe incorrectly the implementation of flow control. The NO_X SIP Call cap and trade program includes similar procedures but flow control was not triggered in the first 2 years of the program (2003 and 2004), so there is no experience to be drawn from that program.

The EPA maintains that the benefits of utilizing these complex procedures is questionable. The EPA has analyzed the use of the flow control procedures in a paper released in March 2004, ''Progressive Flow Control in the OTC NO_X Budget Program: Issues to Consider at the Close of the 1999 to 2002 Period.'' The lessons learned from this analysis were as follows:

(1) Flow control can create market pricing complexity and uncertainty. The need for implementation of flow control for a particular control period is not known more than a few months in advance, and the value of banked allowances varies from year to year, depending on whether flow control has been triggered for the particular year. Therefore, when deciding how much to control, a source has some increased uncertainty about the value of any excess allowances it generates.

(2) Flow control can have a bigger impact on small entities than on large entities. Large firms with multiple allowance accounts can shift banked allowances among those accounts to minimize the number of banked allowances surrendered at a discounted rate.

(3) Flow control does not directly affect short-term emissions, so it may not serve the environmental goals for which it was created.

Incorporating these lessons learned, the EPA is finalizing the CAIR NO_X and SO_2 cap and trade programs with no flow control mechanism.

2. Interpollutant Trading Mechanisms

a. The CAIR NPR Proposal for the Model Rules and Input From Commenters

Mechanisms for interpollutant trading allow reduced emissions of one pollutant to be exchanged for increased emissions of another pollutant where both pollutants cause the same environmental problem (*e.g.*, are precursors of a third pollutant). Interpollutant trading mechanisms are typically based upon each precursor's contribution to a particular environmental problem and are often controversial and scientifically difficult to design because of the complexities of environmental chemistry. Determination of conversion factors (*i.e.*, transfer ratios that relate the impact of one pollutant to the impact of another pollutant) can be dependent upon location, the presence of other pollutants that are necessary for chemical reactions, the time of emissions, and other considerations.

The January 30, 2004 CAIR NPR did not propose a specific interpollutant trading mechanism but rather took comment on interpollutant trading in general as well as the following specific issues:

(1) What would be the exchange rate (*i.e.*, the transfer ratio) for the two pollutants,

(2) How can the transfer ratio best achieve the goals of $PM_{2.5}$ and ozone reductions in downwind States and,

(3) How would the interpollutant trading accommodate the different geographic regions of the $PM_{2.5}$ and ozone programs?

Comments Regarding the Potential Interpollutant Trading

The EPA received several comments on interpollutant trading with the most commenters generally opposed to including provisions to allow for the interchangability of SO_2 and NO_X allowances.

Several commenters pointed out that the CAIR ozone attainment benefits result from the NO_X emissions reductions, and contend that the EPA has not shown that SO_2 emissions impact ozone. Therefore, the commmenters conclude that it would be inappropriate for SO_2 allowances to be traded and used for compliance with the NO_X cap. Some commenters supported the consideration or use of interpollutant trading if it was one-directional, *i.e.*, NO_X allowances could be used for compliance with the SO_2 allowance holding requirements, but not vice versa. This could result in fewer NO_X emissions and more SO_2 emissions.

Some commenters supported the consideration or use of interpollutant trading and emphasized the scientific difficulty in developing accurate transfer ratios. Of these commenters, some added that interpollutant trading would be appropriate if the EPA conducted a thorough analysis of the potential impacts that interpollutant trading would have on: nonattainment areas' ability to come into attainment; the allowance markets and prices; and the integrity of the NO_X caps in light of the potentially large SO_2 allowance bank that might be carried forward into the CAIR trading programs.

A few commenters noted that the EPA is directed by the CAA to study interpollutant trading and has approved SIPs that allow the trading of ozone precursors under specific circumstances.

b. Interpollutant Trading and the Final CAIR Model Rules

Interpollutant trading can provide some additional compliance flexibility, and potentially lower compliance costs, if appropriately applied to multiple pollutants that have reasonably well known impacts on the same environmental problem. The EPA acknowledges that it has the authority to create interpollutant trading programs and has done so, in other regulatory contexts, in the past. However, for several reasons, the EPA determined that direct interpollutant trading is not appropriate in the CAIR.

The final CAIR includes separate annual SO_2 and annual NO_X model rules to address $PM_{2.5}$ precursor emissions, and an ozone-season NO_X model rule to address summertime ozone precursor emissions. The EPA believes it is not appropriate for the CAIR model rules to allow annual SO_2 or NO_X allowances to be used for compliance with ozone-season NO_X allowance holding requirements because this has the potential to adversely impact the ozone-season emissions reductions and ozone air quality improvements from CAIR. This is significant because the EPA, as required by the CAA, has promulgated a national air quality standard for 8-hour ozone based on a determination that the standard is necessary to protect public health. Section 110(a)2(D) requires States to prohibit emissions in amounts that will significantly contribute to nonattainment in, or interfere with maintenance by, any other State with respect to any air quality standard, including ozone. In this rule, EPA has designed the annual (SO_2 and NO_X) and ozone-season (NO_X) emission caps to achieve the emissions reductions necessary to address each State's significant contribution to downwind $PM_{2.5}$ and ozone nonattainment, respectively, and to prevent interference with maintenance. If sources were permitted to use annual SO_2 or annual NO_X allowances for compliance with ozone-season NO_X allowance holding requirements (*i.e.*, the ozone-season NO_X cap), then there would be no assurance that upwind States' ozone-season NO_X reduction obligations would be met, and CAIR's projected ozone improvements in downwind nonattainment areas could be significantly reduced. As a result, should interpollutant trading be permitted between the annual and ozone-season programs, the EPA could not demonstrate that the use of a CAIR ozone-season cap and trade program would result in the emissions reductions necessary to satisfy upwind States' obligations under section 110(a)2(D)to reduce NO_X for ozone purposes.

The EPA believes it is also inappropriate to use annual NO_X allowances for compliance with the annual SO_2 allowance holding requirements, and vice versa. The EPA agrees with commenters that emphasize

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that the chemical interactions for $PM_{2.5}$ precursors are scientifically complex and must be accurately reflected in any transfer ratio in order to maintain the integrity of the market. For example, EPA analysis has shown (see January 30, 2004 NPR) that $PM_{2.5}$ precursors, such as NO_X and SO_2, may have non-linear interactions in the formation of $PM_{2.5}$. Any uniform, interpollutant transfer ratio would have to be an average and would introduce significant variability concerning the impact of interpollutant trading on emissions and significant uncertainty concerning the achievement of the CAIR Program's emission reduction goals. The EPA did not receive a response to the request in the January 30, 2004 NPR for information on an appropriate value for a potential transfer ratio. While the EPA did receive one comment that recommended the use of a trading ratio of two NO_X allowances for one SO_2 allowance, no comments presented supporting analysis that could be used to develop transfer ratios.

While many commenters supportive of allowing interpollutant trading in the CAIR claimed that it would provide additional compliance flexibility to sources, the EPA contends that use of the newly created CAIR trading markets is sufficiently flexible. Sources may develop integrated, multi-pollutant control strategies and use the separate allowance markets to mitigate differences in control costs (within the boundaries of emissions caps). In other words, a source can choose the level to which they can cost effectively control one pollutant and, if necessary, buy or sell emission allowances of the other pollutant to compensate for any expensive or inexpensive control cost. When markets are used to provide for trading of multiple pollutants, sources benefit from the additional compliance flexibility while the caps assure the achievement of the overarching environmental goals.

In the June 10, 2004 SNPR, the EPA solicited comment on how an interpollutant trading mechanism might accommodate the slightly different geographic regions found to be significant contributors for $PM_{2.5}$ and ozone under the CAIR. No commenters provided supporting analysis or input on this issue.

In summary, the EPA received comments that generally opposed including a specific interpollutant trading mechanism. No commenters provided analysis to demonstrate the benefit of including a specific interpollutant trading mechanism nor was there analysis provided in response to the EPA's solicitation in the June 10, 2004 SNPR for input on: Transfer ratios, addressing two different environmental issues, and having slightly different annual NO_X and ozone season NO_X control regions. Furthermore, because the NO_X and SO_2 markets provide very flexible mechanisms for trading of the two pollutants, the EPA does not believe there is a compelling need to go further at this time. Therefore, EPA is not finalizing provisions in the CAIR model rules that specifically address interpollutant trades.

F. Are There Incentives for Early Reductions?

When sources reduce their SO_2 and NO_X emissions prior to the first phase of a multi-phase cap and trade program, it creates the emissions ''glide slope'' of a cap and trade approach that provides early environmental benefit and lowers the cost of compliance. Early reduction credits (ERCs) can provide an incentive for sources to install and/or operate controls before the implementation dates. Allowing emission allowances from existing programs to be used for compliance in the new program is another mechanism to encourage early reductions prior to the start of a cap and trade program. This section discusses the potential use of mechanisms to provide incentives for early reductions in the CAIR.

1. Incentives for Early SO_2 Reductions

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

The January 30, 2004 CAIR NPR and June 10, 2004 CAIR SNPR acknowledge the benefit of early reductions and provide for the use of title IV SO_2 allowances of vintage years 2009 and earlier to be used for compliance in the CAIR at a one-to-one ratio. In other words, title IV allowances can be banked into the CAIR Program. This provides incentive for title IV sources to reduce their emissions in years 2009 and earlier because these allowances may be used for CAIR compliance without being discounted by the retirement ratios applied to the 2010 and later SO_2 allowances. No other mechanism, such as SO_2 ERCs were proposed by the EPA.

Comments Regarding the Incentives for Early SO_2 Reductions

The EPA received comments on incentives for early SO_2 reductions with the majority supporting the EPA proposal to encourage early emission reductions by allowing the CAIR sources to use 2009 and earlier vintage title IV SO_2 allowances for CAIR compliance. Some supporters noted concerns in meeting the CAIR's stringent Phase I SO_2 requirements as another reason to allow the banking of undiscounted, title IV allowances into the CAIR.

Some commenters expressed concern that achieving the SO_2 caps would be delayed if a large number of SO_2 allowances were being banked into the CAIR. Based upon experience with implementing the Acid Rain Program, the EPA acknowledged in the SNPR that crediting early reductions does create a glide slope—where emissions are reduced below the baseline before the implementation date and ''glide'' down to the ultimate cap level sometime after the program begins. This gradual reduction in emissions is a key component to cap and trade programs having lower cost of compliance than command-and-control approaches. One commenter proposed that the EPA needs to assess the likelihood that allowing the banking of undiscounted title IV allowances would delay the attainment of the Phase I SO_2 cap until Phase II. Because the EPA included this mechanism (*i.e.*, the use of 2009 and earlier vintage SO_2 allowances for compliance in the CAIR) in the policy case modeled as part of this rulemaking, EPA analysis includes the benefits and costs that would result from the level of SO_2 reductions that would take place with banking of undiscounted title IV allowances.

One commenter advocated the use of SO_2 ERCs. It was not clear whether these would be awarded in addition to banking title IV allowances into the CAIR or the ERC mechanism would take the place of banking SO_2 allowances into the CAIR.

b. SO_2 Early Reduction Incentives in the Final CAIR Model Rules

The CAIR SO_2 model rule allows CAIR sources to use title IV SO_2 allowances of vintage 2009 and earlier for compliance with the CAIR at a one-to-one ratio. This approach was part of the CAIR policy case assumptions used in the rulemaking modeling and the EPA has shown that the SO_2 cap and trade program, with this early incentive mechanism, will achieve the level of SO_2 reductions needed to meet the CAIR goals. These reductions take place on a glide slope that includes early emissions reductions as well as some use of the SO_2 allowance bank as sources gradually reduce emissions toward the cap levels.

The EPA did not include SO_2 ERCs because the Acid Rain Program cap and trade program, which affects a large segment of the CAIR source universe, makes it impossible to determine whether sources are reducing their SO_2

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emissions below levels required by existing (*i.e.*, the Acid Rain Program) programs. Furthermore, given that most sources with substantial emissions receive SO_2 emission allowances under the Acid Rain Program, a significant number of SO_2 allowances are expected to be banked into the CAIR. These banked allowances would be available to CAIR sources in the early years of the program and make ERCs largely unnecessary.

2. Incentives for Early NO_X Reductions

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

In the June 10, 2004 SNPR, the EPA proposed to provide incentives for early NO_X reductions by allowing the use of NO_X SIP Call allowances of vintage 2009 and earlier to be used for compliance in the CAIR. Further, the EPA did not propose, but solicited comment on the potential use of NO_X ERCs to provide an additional incentive for sources to reduce NO_X emissions prior to CAIR implementation. In addition to the general solicitation for comment on NO_X ERCs, the EPA solicited input on the following specific approaches that could be utilized: (1) The EPA could maintain the NO_X SIP Call requirements and allow sources to use ERCs only for compliance with the annual limitation, to ensure that ozone-season NO_X limitations are met. Under this scenario, the additional States subject to the CAIR that have been found to significantly contribute to ozone nonattainment may also have to be included in the ozone season cap; (2) the EPA could limit the period of time during which ERCs could be created and banked; (3) the EPA could cap the amount of ERCs that can be created; and (4) the EPA could apply a discount rate to ERCs.

Comments Regarding the Incentives for Early NO_X Reductions

The EPA did not receive comment on the proposed use of NO_X SIP Call allowances of vintage years 2009 and earlier for compliance in the CAIR. In fact, several commenters characterized the CAIR proposal as not including any incentives for early NO_X emissions reductions.

The EPA received several comments on the potential use of NO_X ERCs with the majority in favor of some sort of ERC mechanism. Several commenters advocated the use of ERCs to mitigate concerns that they would not be able to meet the stringent Phase I CAIR reduction requirements. One commenter wanted early reductions to facilitate the ozone attainment in 2010 but believed 2010 attainment could only be helped if there were some restrictions on the number of ERCs that could be created.

Some ERC supporters wanted credit for wintertime emissions reductions only, while a few believed that credit should be given for reductions at any time of year. One commenter advocated providing ERCs for wintertime reductions only as part of a broader proposal to create a bifurcated NO_X trading system (*i.e.*, separate wintertime and summertime allowances and trading markets).

Many of the commenters supporting the use of ERCs advocated that they be distributed from a pool of allowances similar to the CSP used in the NO_X SIP Call. (The NO_X SIP Call CSP was a fixed pool of NO_X allowances that were distributed on a first come-first serve, prorated, or need basis, depending upon the State). Commenters noted that the CSP approach has already been part of a litigated rulemaking and provides the added benefit of limiting the total number of allowances that can be distributed for early reductions. Other commenters proposed that should the final approach use a pool of allowances, this pool should not remove allowances from the existing State NO_X budget. Another commenter suggested that allowances from a CSP could be distributed based upon a NO_X emission rate, such as 0.25 lbs/mmBtu. Allowances could be distributed to any source emitting below the target emission rate.

Several commenters were concerned that too many NO_X ERCs (as well as NO_X SIP Call allowances) could be introduced into the CAIR and the ability of the NO_X cap and trade program to meet the annual and ozone-season reduction goals could be compromised. Some commenters suggested that crediting early reductions at a discount (*e.g.*, 2 tons of NO_X reductions earn 1 ERC) could mitigate this concern. Other commenters noted that a CSP-style mechanism also provides safeguards against an overabundance of ERCs. Another commmenter noted that restrictions on the use of ERCs similar to the progressive flow control (PFC) mechanism used in the NO_X SIP Call—PFC restricts the use of banked NO_X allowances for compliance in years where the NO_X bank is greater than 10 percent of the allocations—could help to ease concerns of flooding the market with NO_X ERCs.

One commenter believed that the EPA's projection that the potential pool of NO_X ERCs could be as large as 3.7 million tons (presented in the June 10, 2004 SNPR) is unrealistically high. The commenter contended that technical limitations of Selective Catalytic Reduction (SCR) operation would not permit facilities to simply run all of their SCRs year-round. More specifically, the commenter believes the lower operating loads, typically of the wintertime dispatch, would not meet the minimum conditions necessary for SCR operation (*i.e.*, at lower capacity the stack gas temperatures will not support the use of the catalyst). Fewer wintertime opportunities to operate the SCRs is believed by the commenter to result in a smaller projected ERC estimate. This was an estimate used for discussion purposes and was not directly used in the development of the CSP.

A few commenters advocated providing credits to any source that reduced emission rates below those used to determine the CAIR State budgets. One commenter suggested that the rates be based on those rates used to determine the NO_X SIP Call caps.

A few commenters proposed that the EPA should develop a strategy for crediting NO_X reductions from sources that have implemented control measures in response to State-level regulations that are more stringent than the NO_X SIP Call. Another commenter advocated only providing ERCs in States subject to both the NO_X SIP Call and the CAIR.

Some commenters did not support the use of NO_X ERCs in any form. These commenters believe that the use of ERCs would delay attainment of the CAIR emission caps.

b. NO_X Early Reduction Incentives in the Final CAIR Model Rules

The CAIR ozone-season NO_X cap and trade rule will allow the proposed use of NO_X SIP Call allowances of vintage years 2008 and earlier for compliance in the CAIR. This mechanism would provide incentive for sources in NO_X SIP Call States to reduce their ozone-season NO_X emissions and bank additional allowances into the CAIR. Because today's final ozone-season cap and trade rule includes a mandatory ozone-season NO_X cap in 2009 (this modification is discussed in section IV), the provisions to allow the banking of NO_X SIP Call allowances into the CAIR are adjusted to reflect this implementation date.

The CAIR annual NO_X cap and trade rule will provide additional incentives for early annual NO_X reductions by creating a CSP for CAIR States from which they can distribute allowances for early, surplus NO_X emissions reductions in the years 2007 and 2008. The earning of CAIR CSP allowances for

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NO_X emission reductions does not begin until 2007 because this is the first year after the State SIP submittal deadlines. The CAIR CSP will provide a total of 200,000 [136] CAIR annual NO_X allowances of vintage 2009 in addition to the annual CAIR NO_X budgets.

The CAIR's CSP is patterned after the NO_X SIP Call's CSP, which is part of an established and extensively litigated rulemaking. Similarities include: Limiting the total number of allowances that can be distributed; limiting the years in which CSP allowances can be earned; populating the CSP with allowances vintaged the first compliance year; and using distribution criteria of early reductions and need.

The EPA will apportion the CSP to the States based upon their share of the final, regionwide NO_X CAIR reductions. Similar to the NO_X SIP Call, States may distribute these CAIR NO_X allowances to sources based upon either: (1) A demonstration by the source to the State of NO_X emissions reductions in surplus of any existing NO_X emission control requirements; or (2) a demonstration to the State that the facility has a "need" that would affect electricity grid reliability. Sources that wish to receive CAIR CSP allowances based upon a demonstration of surplus emissions reductions will be awarded one CAIR annual NO_X allowance for every ton of NO_X emissions reductions. (Should a State receive more requests for allowances than their share of the CAIR CSP, the State would pro-rate the allowance distribution.) Determination of surplus emissions must use emissions data measured using part 75 monitoring.

The EPA elected to include the CSP in response to several comments noting the benefit of early NO_X reductions and some commenters concerns in complying with the stringent Phase I CAIR NO_X cap. While EPA analysis has shown that sources had sufficient time to install NO_X emission controls, the EPA does believe that it would be appropriate to provide some mechanism to alleviate the concerns of some sources which may have unique issues with complying with the 2009 implementation deadline. In addition to mitigating some of the uncertainty regarding the EPA projections of resources to comply with CAIR, the CAIR CSP also effectively provides incentives for early, surplus NO_X reductions.

The EPA agrees with the comments that advocate allowing sources to earn CAIR annual NO_X allowances only for those reductions that are in surplus of the sources' existing NO_X reduction requirements. By allowing sources in NO_X SIP Call and non-NO_X SIP Call States to demonstrate that their year-round early reductions are truly "surplus" and, therefore, deserving of CSP allowances, the EPA is responding to comments that the EPA should allow sources in non-NO_X SIP Call States to receive credit for early reductions. Some commenters advocated crediting sources in the ozone-season NO_X cap and trade program that emitted below the emission rate used to determine the ozone-season budget. The EPA did not accept this recommendation because a source that is allowed to bank NO_X SIP Call allowances into the CAIR ozone-season NO_X program and receive early reduction credit from CAIR's CSP would be essentially "double-counting" that emission reduction.

The EPA did not restrict the use of the NO_X allowances awarded from the CSP because several aspects of the CSP already address concerns that too many total credits would be distributed and that they would flood the markets. First, the CSP is a finite pool of NO_X allowances. Second, by requiring sources to reduce one ton of NO_X emissions for every NO_X allowance awarded from the CSP ensures that significant reductions are made prior to the CAIR implementation date.

G. Are There Individual Unit "Opt-In" Provisions?

In the SNPR, EPA described a potential approach for allowing certain units to voluntarily participate in, or "opt-in," to the CAIR. Originally, EPA proposed to have no opt-in provision but included language in the SNPR on what a potential opt-in provision may look like. This "potential" opt-in provision would have allowed non-EGU boilers and turbines that exhaust to a stack or duct and monitor and report in accordance with part 75 to opt into the CAIR. The opt-in unit would have been required to opt-in for both SO_2 and NO_X. The allocation method for opt-ins assumed a percentage SO_2 reduction from a baseline and for NO_X, allocations were equal to a baseline heat input multiplied by a specified NO_X emissions rate, the same NO_X emissions rate EGUs were subject to in the assumed EGU budgets. Allocations were updated annually and after opting in units would have had to stay in the CAIR for a minimum of 5 years. The EPA received many comments in favor of and very few comments against including an opt-in provision in the final rule. As a result, EPA is including an opt-in provision in this final rule that is based on the approach described in the SNPR but includes several modifications and additions in response to comments as described below. In general, EPA believes there is value to including an opt-in provision but believes that sources that opt-in should be responsible for a certain level of reduction below its baseline because of the additional flexibility provided to that source by opting into a regional trading program and because of the possibility that participation in the CAIR may reduce or eliminate future potential required reductions. Therefore, the following opt-in approach has as its goals to provide more flexibility to the units opting in as well as to potentially provide more cost-effective reductions for the affected EGUs but also to ensure a certain level of reduction from the units opting into the program.

1. Applicability

Some commenters suggested that the opt-in provision not be limited to boilers and turbines but should be open to any unit. The EPA strongly believes that any unit participating in an emissions trading program be subject to accurate and reliable monitoring and reporting requirements. This is the purpose of part 75. The EPA has developed criteria for boilers and turbines to satisfy the requirements of part 75 but has not developed criteria for all non-boilers and turbines and, therefore, cannot be confident their emissions can be monitored with the high degree of accuracy and reliability required by a cap-and-trade program. Continuous Emissions Monitoring Systems or "CEMS" are typically what is required by EPA to participate in a cap-and-trade program.

In response to comments received suggesting that non-boilers and turbines be allowed to opt-in, EPA is expanding applicability of the opt-in provision to include, in addition to boilers and turbines, other fossil fuel-fired combustion devices that vent all emissions through a stack and meet monitoring, recordkeeping, and recording requirements of part 75.

2. Allowing Single Pollutant

Some commenters suggested that sources should be allowed to opt-in for only one pollutant instead of requiring the source to opt-in for both SO_2 and NO_X as EPA proposed. These commenters argued that some sources may only emit significant amounts of one of the two regulated pollutants and that it would not make sense to require reductions in both pollutants from such

[136] The 200,000 ton pool includes the 1,503 tons that would be DE and NJ's share. Section V of today's action describes in detail the State-by-State apportionment of the total CSP.

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a source. The EPA agrees with this comment and will allow units to opt-in for one pollutant, *i.e.*, NO_X, SO_2, or both. Another commenter suggested that EPA allow non-EGUs subject to the NO_X SIP Call to opt into the CAIR for NO_X only without requiring any reductions in SO_2. This commenter argued that these non-EGUs could simply turn on their SCRs during the non-ozone season and easily achieve significant NO_X reductions. The EPA agrees that the relatively small number of non-EGUs subject to the NO_X SIP Call that have SCRs could achieve significant NO_X reductions by operating their SCRs during the non-ozone season. As stated above, EPA is allowing sources to opt-in for one pollutant and thus non-EGUs subject to the NO_X SIP call may opt-in for NO_X only.

3. Allocation Method for Opt-Ins

In the SNPR, EPA proposed allocating allowances to opt-in units on a yearly basis. The amount of allowances allocated would be calculated by multiplying an emission rate by the lesser of a baseline heat input or the actual heat input monitored at the unit in the prior year.

The baseline heat input would be calculated by using the most recent 3 years of quality-assured part 75 monitoring data. When less than 3 years of quality-assured part 75 monitoring data is available, the heat input would be based on quality-assured part 75 monitoring data from the year before the unit opted in.

For SO_2, EPA proposed that the emission rate used to calculate allocations would be the lesser of, the most stringent State or Federal SO_2 emission rate that applied in the preceding year or the emission rate representing 50 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu) for the years 2010 through 2014 and 35 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu) for 2015 and beyond. For NO_X, EPA proposed that the emission rate would be the lower of the unit's baseline emission rate, the most stringent State or Federal NO_X emission limitation that applies to the opt-in unit at any time during the calender year prior to opting into the CAIR Program, or 0.15 lb/mmBtu for the years 2010 through 2014 and 0.11 lbs/mmBtu for the years 2015 and beyond.

In today's final rule, EPA is making a number of changes to its proposed methodology for calculating allocations for opt-in units.

With regards to baseline heat input, EPA is requiring that sources may only use part 75 monitored data for years in which they have maintained at least a 90 percent monitor availability. The EPA is making this change because part 75 contains missing data provisions that require substitution of data when monitors are unavailable. When units have low monitor availability, units are required to report more conservative (*e.g.*, higher) heat input values. This is to provide an incentive to maintain high monitor availability (since under a cap and trade program sources would be required to turn in more allowances if they reported higher emissions). When setting baselines, sources have the opposite incentive, reporting a higher heat input would result in a higher baseline and thus a greater allocation.

With regards to the SO_2 emission rate used to calculate allocations, EPA is requiring that the emission rate used to calculate allocations would be the lesser of, the most stringent State or Federal SO_2 emission rate that applies to the unit in the year that the unit is being allocated for, or the emission rate representing 70 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu). The EPA is changing the percentage emission reduction upon which allocations are based because some commenters suggested that instead of using percentage emission reduction requirements that are the same as the requirements for EGUs as a basis for allocating to opt-ins, EPA should require emissions reductions based on similar marginal cost of control. The EPA agrees with the basic concept that emissions reductions for opt-ins should be based on similar marginal costs. One commenter submitted results from a study of industrial boiler NO_X and SO_2 control costs that indicated the use of similar marginal cost of control would result in approximately a 30 percent reduction in NO_X and SO_2 by 2010. While the commenter provided limited data to allow EPA to evaluate the commenter's estimates, EPA is using this percentage reduction requirement for the opt-in provision. The same commenter stated that it may be possible to achieve more than a 30 percent reduction in SO_2 and NO_X by 2015 by employing future unspecified technology advances. Because these future technology advances are not specified nor demonstrated, EPA is not requiring more than a 30 percent reduction in SO_2 and NO_X in 2015 and beyond for opt-ins. The EPA is changing the requirement to use the lowest required emission rate for the year preceding the year in which allowances are being allocated to the lowest emission rate for the year in which allowances are being allocated. The EPA is making this change because EPA believes that such data should be available and that this more accurately reflects the intent of the rule to ensure that the source is not being allocated a greater number of allowances than the emissions a source would be allowed to emit under the regulations it is subject to in the year the allocations are being made. The EPA is finalizing parallel provisions with respect to NO_X.

4. Alternative Opt-In Approach

Some commenters suggested that EPA include an alternative approach to opting into the CAIR. This alternative would allow units to opt-in as early as 2009 for NO_X and 2010 for SO_2 and receive allocations at their current emission levels in return for a commitment to make deeper reductions by 2015 than would be required under the general opt-in provision described above. Therefore, for the years 2010 through 2014, the unit would be allocated allowances based on the same heat input used under the general opt-in provision (*e.g.*, the lesser of the baseline heat input or the heat input for the year preceding the year in which allocations are being made) multiplied by an emission rate. This emission rate would be the lower of the emission rate for the year or years before the unit opted in or the most stringent State or Federal emission rate required in the year that the unit opts in. For SO_2 for the years 2015 and beyond, the unit would be allocated allowances based on the same heat input multiplied by an emission rate. This emission rate would be the lower of a 90 percent reduction from the baseline emission rate or the most stringent State or Federal emission rate required in the baseline year. For NO_X, the same methodology would be used, except that the emission rate used for the years 2015 and beyond would be the lower of 0.15 lbs/mmBtu or the most stringent State or Federal emission rate required in the baseline year. The EPA believes the environmental benefit of achieving deeper emissions reductions in the future (2015) from sources that may otherwise not make such deep emissions reductions is worth including in this final rule.

5. Opting Out

In the SNPR, EPA proposed that opt-in units be required to remain in the program a minimum of 5 years after which time they could voluntarily withdraw from the CAIR. Some commenters expressed concern over this proposed approach, arguing that because EGUs affected by the CAIR are not allowed to voluntarily withdraw from the CAIR that opt-in sources should not be allowed to voluntarily withdraw either. The EPA recognizes that opt-in sources such as industrial boilers and turbines tend to be more sensitive to changing market forces than EGUs. As a result, EPA believes it is appropriate to allow opt-in sources who voluntarily participate in an emissions reductions program to be able to end their participation or (''opt-out'') after a specified period of time. As proposed, EPA believes a period of 5 years is appropriate and is finalizing a rule to allow opt-in sources to opt-out after participating in the CAIR for 5 years. This option to opt-out after 5 years does not apply to sources that opt-in under the alternative approach. Sources that opt-in under the alternative approach may not opt-out at any time.

6. Regulatory Relief for Opt-In Units

The CAIR does not offer relief from other regulatory requirements, existing or future, for units that opt-in to the CAIR cap and trade program. Any revision of requirements for other, non-CAIR programs would be done under rulemakings specific to those programs.

As discussed above, EPA is including two different approaches for opt-in units to follow, a general and an alternative approach. The EPA is including both approaches in this final rule in response to comments supportive of including an alternative means and to provide greater flexibility for sources to participate in the CAIR trading program. Opt-in sources may select which approach is more appropriate for their particular situation. An opt-in source may not switch from one approach to the other once in the program. States have the flexibility to choose to include both of these approaches, one of these approaches, or none of them in their SIPs. EPA is not requiring States to include an individual unit opt-in provision because the participation of individual opt-in units is not required to meet the goals of the CAIR. However, States cannot choose to have an individual unit opt-in approach different than what EPA has finalized in this rule and still participate in the inter-State trading program administered by EPA.

H. What Are the Source-Level Emissions Monitoring and Reporting Requirements?

In the NPR, the EPA proposed that sources subject to the CAIR monitor and report NO_X and SO_2 mass emissions in accordance with 40 CFR part 75.

The model trading rules incorporate part 75 monitoring and are being finalized as proposed. The majority of CAIR sources are measuring and reporting SO_2 mass emissions year round under the Acid Rain Program, which requires part 75 monitoring. Most CAIR sources are also reporting NO_X mass emissions year round under the NO_X SIP Call. The CAIR-affected Acid Rain sources that are located in States that are not affected by the NO_X SIP Call currently measure and report NO_X emission rates year round, but do not currently report NO_X mass emissions. These sources will need to modify only their reporting practices in order to comply with the proposed CAIR monitoring and reporting requirements.

Because so many sources are already using part 75 monitoring, there were very few comments on the source-level monitoring requirements in this rulemaking. The comments the EPA received related to sources not currently monitoring under part 75. Commenters suggested that alternative forms of monitoring (*e.g.*, part 60 monitoring) would be appropriate for these sources. The EPA disagrees. Consistent, complete and accurate measurement of emissions ensures that each allowance actually represents one ton of emissions and that one ton of reported emissions from one source is equivalent to one ton of reported emissions from another source. Similarly, such measurement of emissions ensures that each single allowance (or group of SO_2 allowances, depending upon the SO_2 allowance vintage) represents one ton of emissions, regardless of the source for which it is measured and reported. This establishes the integrity of each allowance, which instills confidence in the underlying market mechanisms that are central to providing sources with flexibility in achieving compliance. Part 75 has flexibility relating to the type of fuel and emission levels as well as procedures for petitioning for alternatives. The EPA believes this provides the requested flexibility.

Should a State(s) elect to use the example allocation approach, the EPA would modify the part 75 monitoring and reporting requirements to collect information used in determining the allowance allocations for Combined Heat and Power (CHP) units. More specifically, provisions for the monitoring and reporting of the BTU content of the steam output would be added to the existing requirements. The information on electricity output currently reported under part 75 would not need to be revised to allow States to implement the example allowance allocation approach.

In the SNPR, the EPA proposed continuous measurement of SO_2 and NO_X emissions by all existing affected sources by January 1, 2008 using part 75 certified monitoring methodologies. New sources have separate deadlines based upon the date of commencement of operation, consistent with the Acid Rain Program. These deadlines are finalized as proposed.

I. What Is Different Between CAIR's Annual and Seasonal NO_X Model Cap and Trade Rules?

Today's action finalizes not only the proposed CAIR annual NO_X program and annual SO_2 program, but also a CAIR ozone-season NO_X program. Because the CAIR ozone-season NO_X program is the only ozone-season NO_X cap and trade program that the EPA will administer, NO_X SIP Call States wishing to meet their NO_X SIP Call obligations through an EPA-administered regional NO_X program will also use the CAIR ozone-season rule. The EPA believes that States and affected sources will benefit from having a single, consistent regional NO_X cap and trade program. This section of today's action highlights any key differences between the CAIR ozone-season NO_X model rule and the NO_X SIP Call model rule, as well as the CAIR annual and ozone-season NO_X model rules.

Differences Between the CAIR Ozone-Season NO_X Model Rule and the NO_X SIP Call Model Rule

While the CAIR ozone-season NO_X model rule closely mirrors the NO_X SIP Call rule (as does the other CAIR rules), the EPA has incorporated into the CAIR model rules its experience with implementing trading programs (including seasonal NO_X programs). These modifications include the following.

A. Unrestricted banking: The CAIR ozone-season NO_X model rule will not include any restrictions on the banking of NO_X SIP Call allowances (vintages 2008 and earlier) or CAIR ozone-season NO_X allowances. The NO_X SIP Call rules include ''progressive flow control'' provisions that reduce the value of banked allowances in years where the bank is above a certain percentage of the cap. (See section VIII.E.1 of today's rule for a detailed discussion).

B. Facility level compliance: The CAIR ozone-season NO_X model rule will allow sources to comply with the allowance holding requirements at the facility level. The NO_X SIP Call rules required unit-by-unit level compliance with certain types of allowance accounts providing some flexibility for sources with multiple affected units. (See the June 2004 SNPR, section IV for a detailed discussion).

The EPA believes that these changes improve the programs and that both CAIR and NO_X SIP Call affected sources

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will benefit from complying with a single, regionwide cap and trade program.

Differences Between the CAIR Ozone-Season and Annual NO_X Model Rules

The CAIR ozone-season and annual NO_X model rules are designed to be identical with the exception of (1) provisions that relate to compliance period and (2) the mechanism for providing incentives for early NO_X reductions. For compliance related provisions, the EPA attempted to maintain as much consistency as possible between the CAIR annual and ozone-season NO_X model rules. For example, reporting schedules remain synchronized (*i.e.*, quarterly reporting) for both of the CAIR NO_X model rules. For the annual and ozone-season NO_X model rules, the EPA did define 12 month and 5 month compliance periods, respectively.

Incentives for early NO_X reductions differ between the CAIR annual and ozone-season programs. For the annual NO_X program, early reductions may be rewarded by States through a CSP. (See section VIII.F.2 of today's action for a detailed discussion.) The CAIR ozone-season NO_X model rule provides incentive for early emissions reductions by allowing the banking of pre-2009 NO_X SIP Call allowances into the CAIR ozone-season program.

J. Are There Additional Changes to Proposed Model Cap and Trade Rules Reflected in the Regulatory Language?

The proposed and final rules are modeled after, and are largely the same as, the NO_X SIP Call model trading rule. Today's final rule includes some relatively minor changes to the model rules' regulatory text that improve the implementability of the rules or clarify aspects of the rules identified by the EPA or commenters. (Note that sections VIII.B through VIII.H of today's action highlight the more significant modifications included in the final model rules).

One example of a relatively minor change is the inclusion of language in the SO_2 model rule that implements the retirement ratio (2.00) used for allowances allocated for 2010 to 2014 and the retirement ratio (2.86) used for allowances allocated for 2015 and later, that clarifies the compliance deduction process and that provides for rounding-up of fractional tons to whole tons of excess emissions. More specifically, the definition of ''CAIR SO_2 allowance'' states that an allowance allocated for 2010 to 2014 authorizes emissions of 0.50 tons of SO_2 and that an allowance allocated for 2015 or later authorizes emissions of 0.35 tons of SO_2—which corresponds with the 2.86 retirement ratio.

Other, less significant modifications were also included in the regulatory text of the final model rules. These include:

C. Units and sources are identified separately for NO_X and SO_2 programs (*e.g.*, CAIR NO_X units, CAIR Nox ozone season units, and CAIR SO_2 units) since States can participate in one, two, or three trading programs;

D. The definition of ''nameplate capacity'' is clarified;

E. The language on closing of general accounts is clarified; and,

F. Process of recordation of CAIR SO_2 allowance allocations and transfers on rolling 30-year periods is added to make it consistent with Acid Rain regulations.

Another example of where today's final model trading rules incorporate relatively minor changes from the proposed model trading rules involves the provisions in the standard requirements concerning liability under the trading programs. The proposed CAIR model NO_X and SO_2 trading rules include, under the standard requirements in § 96.106(f)(1) and (2) and § 96.206(f)(1) and (2), provisions stating that any person who knowingly violates the CAIR NO_X or SO_2 trading programs or knowingly makes a false material statement under the trading programs will be subject to enforcement action under applicable State or Federal law. Similar provisions are included in § 96.6(f)(1) and (2) of the final NO_X SIP Call model trading rule. The final CAIR model NO_X and SO_2 trading rules exclude these provisions for the following reasons. First, the proposed rule provisions are unnecessary because, even in their absence, applicable State or Federal law authorizes enforcement actions and penalties in the case of knowing violations or knowing submission of false statements. Moreover, these proposed rule provisions are incomplete. They do not purport to cover, and have no impact on, liability for violations that are not knowingly committed or false submissions that are not knowingly made. Applicable State and Federal law already authorizes enforcement actions and penalties, under appropriate circumstances, for non-knowing violations or false submissions. Because the proposed rule provisions are unnecessary and incomplete, the final CAIR model NO_X and SO_2 trading rules do not include these provisions. However, the EPA emphasizes that, on their face, the provisions that were proposed, but eliminated in the final rules, in no way limit liability, or the ability of the State or the EPA to take enforcement action, to only knowing violations or knowing false submissions.

IX. Interactions With Other Clean Air Act Requirements

A. How Does This Rule Interact With the NO_X SIP Call?

A majority of States affected by the CAIR are also affected by the NO_X SIP Call. This section addresses the interactions between the two programs.

The EPA proposed that States achieving all of the annual NO_X reductions required by the CAIR from only EGUs would not need to continue to impose seasonal NO_X limitations on EGUs from which they required reductions for purposes of complying with the NO_X SIP Call. Also, EPA proposed that States would have the option of retaining such seasonal NO_X limitations. The EPA also proposed to keep the NO_X SIP Call in place for non-EGUs currently subject to the NO_X SIP Call and to continue working with States to run the NO_X SIP Call Budget Trading Program for all sources that would remain in the program. In response to commenters, EPA is making several modifications to its proposed approach.

States Affected by the CAIR for Ozone and $PM_{2.5}$ Will Be Subject to a Seasonal and an Annual NO_X Limitation

A number of commenters recommended leaving the current NO_X SIP Call ozone season NO_X limitation in place as a way to ensure that ozone season NO_X reductions from EGUs required by the NO_X SIP Call would continue to be achieved. Some commenters argued this would also help non-EGUs currently subject to the NO_X SIP Call by allowing them to continue trading with EGUs in a seasonal NO_X program. Many of the same commenters suggested a dual-season or bifurcated CAIR trading program as a mechanism for maintaining an ozone season NO_X limitation for EGUs under the CAIR. In response to these commenters, EPA is requiring that States subject to the CAIR for $PM_{2.5}$ be subject to an annual limitation and that States subject to the CAIR for ozone be subject to an ozone season limitation. This means that States subject to the CAIR for both $PM_{2.5}$ and ozone are subject to both an annual and an ozone season NO_X limitation. The annual and ozone season NO_X limitations are described in section IV. States subject to the CAIR for ozone only are only subject to an ozone season NO_X limitation. To implement these NO_X limitations, EPA will establish and operate two NO_X trading programs, *i.e.*,

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a CAIR annual NO_X trading program and a CAIR ozone season NO_X trading program. The CAIR ozone season NO_X trading program will replace the current NO_X SIP Call as discussed in more detail later in this section.

What Will Happen to Non-EGUs Currently in the NO_X SIP Call?

A number of commenters were concerned that the cost of compliance for non-EGUs in the NO_X SIP Call would increase if they were not allowed to continue to trade with EGUs. In response to these commenters, EPA is modifying its proposed approach. The EPA is allowing States affected by the NO_X SIP Call that wish to use EPA's model trading rule to include non-EGUs currently covered by the NO_X SIP Call in the CAIR ozone season NO_X trading program. This will ensure that non-EGUs in the NO_X SIP Call will continue to be able to trade with EGUs as they currently do under the NO_X SIP Call. This will not require States to get additional reductions from non-EGUs. Budgets for these units would remain the same as they are currently under the NO_X SIP Call. States will, however, be required to modify their existing NO_X SIP Call regulations to reflect the replacement of the NO_X SIP Call with the CAIR ozone season NO_X trading program. The EPA will continue to operate the NO_X SIP Call trading program until implementation of the CAIR begins in 2009. The EPA will no longer operate the NO_X SIP Call trading program after the 2008 ozone season and the CAIR ozone season NO_X trading program will replace the NO_X SIP Call trading program. If States affected by the NO_X SIP Call do not wish to use EPA's CAIR ozone season NO_X trading program to achieve reductions from non-EGU boilers and turbines required by the NO_X SIP Call, they would be required to submit a SIP Revision deleting the requirements related to non-EGU participation in the NO_X SIP Call Budget Trading Program and replacing them with new requirements that achieve the same level of reduction.

Compliance With the NO_X SIP Call for States That Are Subject to Both the CAIR Ozone Season NO_X Reduction Requirements and the NO_X SIP Call

If the only changes a State makes with respect to its NO_X SIP Call regulations are: (1) To bring non-EGUs that are currently participating in the NO_X SIP Call Budget Trading Program into the CAIR ozone season program using the same non-EGU budget and applicability requirements that are in their existing NO_X SIP Call Budget Trading Program; and (2) to achieve all of the emissions reductions required under the CAIR from EGUs by participating in the CAIR ozone season NO_X trading program, EPA will find that the State continues to meet the requirements of the NO_X SIP Call.

If the only changes a State makes with respect to its NO_X SIP Call regulations are not those described above, see section VII for a discussion of how the State would satisfy its NO_X SIP Call obligations.

States in the NO_X SIP Call But Not Affected by the CAIR (Rhode Island)

Rhode Island is the only State in the NO_X SIP Call that is not affected by the CAIR. To continue meeting its NO_X SIP Call obligations in 2009 and beyond, Rhode Island will have two choices. It may either modify its NO_X SIP Call trading rule to conform to the new CAIR ozone season NO_X trading rule if it wishes to allow its sources to continue to participate in an interstate NO_X trading program run by EPA or, it will need to develop an alternative method for obtaining the required NO_X SIP Call reductions. In either case, Rhode Island must continue to meet the budget requirements of the existing NO_X SIP Call.

Use of Banked SIP Call Allowances in the CAIR Program

As explained earlier in today's final rule, banked allowances from the NO_X SIP Call may be used in the CAIR ozone season NO_X trading program.

Other Comments and EPA's Responses

One commenter wrote that because attainment demonstrations for early action compacts were made based on having EGUs and non-EGUs together in the NO_X SIP Call, EPA could not allow EGUs to leave the NO_X SIP Call and still have valid early action compacts (EACs). As discussed above, EPA is allowing States to keep EGUs and non-EGUs in the NO_X SIP Call together in one ozone season program (CAIR ozone season trading program). The NO_X reductions required by the CAIR ozone season trading program are slightly more stringent than the reductions required by the NO_X SIP Call. As a result, the attainment demonstrations for EACs would remain valid under the CAIR. Having said that, the EAC program will have ended (April 2008) before the CAIR rule is implemented. Thus, the compacts will no longer be applicable when the CAIR takes effect.

Another commenter proposed to have non-EGUs under the NO_X SIP Call subject to an annual NO_X cap similar to EGUs under the CAIR so that non-EGUs could continue to trade with EGUs. By adopting a CAIR ozone season trading program that includes non-EGUs covered by the NO_X SIP Call, non-EGUs will be able to continue to trade with EGUs.

B. How Does This Rule Interact With the Acid Rain Program?

As EPA developed this regulatory action, much consideration was given to interactions between the existing title IV Acid Rain Program and today's action designed to achieve significant reductions in SO_2 emissions beyond title IV. Requiring sources to reduce emissions beyond what title IV mandates has both environmental and economic implications for the existing title IV SO_2 cap and trade program. In the absence of an approach for taking account of the title IV program, a new program (*i.e.*, the CAIR) that imposes a significantly tighter cap on SO_2 emissions for a region encompassing most of the sources and most of the SO_2 emissions covered by title IV would likely result in a significant excess in the supply of title IV allowances, a collapse of the price of title IV allowances, disruption of operation of the title IV allowance market and the title IV SO_2 cap and trade system, and the potential for increased SO_2 emissions. The potential for increased emissions would exist in the entire country for the years before the CAIR implementation deadline and would continue after implementation for States not covered by the CAIR. These negative impacts, particularly those on the operation of the title IV cap and trade system, would undermine the efficacy of the title IV program and could erode confidence in cap and trade programs in general.

Title IV has successfully reduced emissions of SO_2 using the cap and trade approach, eliminating millions of tons of SO_2 from the environment and encouraging billions of dollars of investments by companies in pollution controls to enable the sale of allowances reflecting excess emissions reductions and in allowance purchases for compliance. In view of these already achieved reductions and existing investments under title IV, the likelihood of disruption of the allowance market and the title IV cap and trade system, and the potential for SO_2 emission increases, it is necessary to consider ways to preserve the environmental benefits achieved under title IV and maintain the integrity of the market for title IV allowances and the title IV cap and trade system. The EPA maintains that it is appropriate to provide States the opportunity to achieve the SO_2 emission reductions

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required under today's action by building on, and avoiding undermining, this existing, successful program.

The EPA has developed, in the model SO_2 cap and trade rule, an approach to build on and coordinate with the title IV SO_2 program to ensure that the required reductions under today's action are achieved while preserving the efficacy of the title IV program. The EPA's approach provides States the opportunity to impose more stringent control requirements for EGUs' SO_2 emissions than under title IV through an EPA-administered cap and trade program that requires the use of title IV allowances for compliance at a ratio of 2 allowances per ton of emissions for allowances allocated for 2010 through 2014 and 2.86 allowances per ton of emissions for allowances allocated for 2015 or thereafter. (The program also allows the use of banked title IV allowances allocated for years before 2010 to be used at a ratio of 1 allowance per ton of emissions.) Title IV allowances continue to be freely transferable among sources covered by the Acid Rain Program and sources covered by the model SO_2 cap and trade program under CAIR. However, each title IV allowance used to comply with a source's allowance-holding requirement in the CAIR model SO_2 cap and trade program is removed from the source's allowance tracking system account and cannot be used again for compliance, either in the CAIR model SO_2 cap and trade program or the Acid Rain Program.

In addition, as discussed above, if a State wants to achieve the SO_2 emissions reductions required by today's action through more stringent EGU emission limitations only but without using the model cap and trade program, then EPA is requiring that the State include in its SIP a mechanism for retiring the excess title IV allowances that will result from imposition of these more stringent EGU requirements. In this case, the State must retire an amount of title IV allowances equal to the total amount of title IV allowances allocated to the units in the State minus the amount of title IV allowances equivalent to the tonnage cap set by the State on SO_2 emissions by EGUs, and the State can choose what retirement mechanism to use.

Further, as discussed above, if a State wants to meet the SO_2 emissions reductions requirement in today's action through reductions by both EGUs and non-EGUs, then EPA is also requiring the State's SIP to include a mechanism for retiring excess title IV allowances. In that case, the amount of title IV allowances that must be retired equals the total amount of title IV allowances allocated to the units in the State minus the amount of title IV allowances equivalent to the tonnage cap set by the State on EGU SO_2 emissions, and the State can choose what retirement mechanism to use.

Finally, as discussed above, if the State wants to achieve the SO_2 emissions reductions requirement in today's action through reductions by non-EGUs only, then EPA is not imposing any requirement to retire title IV allowances.

1. Legal Authority for Using Title IV Allowances in CAIR Model SO_2 Cap and Trade Program

The EPA maintains that it has the authority to approve and administer, if requested by a State in the SIP submitted in response to today's action, the new CAIR model SO_2 cap and trade program meeting the SO_2 emission reduction requirement in today's action that requires use of title IV allowances to comply with the more stringent allowance-holding requirement of the new program and retirement under the CAIR SO_2 cap and trade program and the Acid Rain Program of title IV allowances used for such compliance. Some commenters claim that EPA's establishment of such a cap and trade program using title IV allowances that sources must hold generally at a ratio of greater than one allowance per ton of SO_2 emissions is contrary to title IV. Most of these commenters prefer the approach of allowing States to use a new EPA-administered cap and trade program to meet lawful emission reduction requirements under title I and of allowing (but not requiring) sources to use title IV allowances in the new program. However, these commenters argue that title IV prohibits requiring sources to use title IV allowances in such a program, whether at the same tonnage authorization (*i.e.*, one allowance per ton of emissions) established in title IV or at a different tonnage authorization. Other commenters state that title IV does not bar EPA from establishing a new cap and trade program that requires the use of title IV allowances.

The EPA maintains that it has the authority under section 110(a)(2)(D) and title IV to establish a new cap and trade program requiring the use of title IV allowances at a different tonnage authorization than under the Acid Rain Program and the retirement of such allowances for purposes of both programs. First, as discussed in section V above, EPA has the authority under section 110(a)(2)(D) to establish a new SO_2 cap and trade program, administered by EPA if requested in a State's SIP, to prohibit emissions that contribute significantly to nonattainment, or interfere with maintenance, of the $PM_{2.5}$ NAAQS. Further, EPA notes that under section 402(3), a title IV allowance is:

> An authorization, allocated to an affected unit by the Administrator under this title [IV], to emit, during or after a specified calendar year, one ton of sulfur dioxide. 42 U.S.C. 7651(a)(3).

However, section 403(f) states that:

> An allowance allocated under this title is a limited authorization to emit sulfur dioxide in accordance with the provision of this title [IV]. Such allowance does not constitute a property right. Nothing in this title [IV] or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. Nothing in this section relating to allowances shall be construed as affecting the application of, or compliance with, any other provision of this Act to an affected unit or source, including the provisions related to applicable National Ambient Air Quality Standards and State implementation plans. 42 U.S.C. 7651b(f).

The EPA interprets the reference in section 403(f) to the authority of the ''United States'' to terminate or limit the authorization otherwise provided by a title IV allowance to mean that EPA (acting in accordance with its authority under other provisions of the CAA), as well as Congress, has such authority.[137]

[137] The EPA's interpretation is based on the language of section 403(f) and the legislative history of the provision. The language in CAA section 403(f) contrasts with language that was in section 503(f) of the House bill—but was excluded from the final version of the CAA Amendments of 1990—referring to the authority of the ''United States'' to terminate or limit such authorization ''by Act of Congress'' and stating that ''[a]llowances under this title may not be extinguished by the Administrator.'' U.S. Senate Committee on Environment and Public Works, *A Legislative History of The Clean Air Act Amendments of 1990* (*Legis. Hist. of CAAA*), S. Prt. 38, 103d Cong., 1st Sess., Vol. II at 2224 (Nov. 1993). Further, unlike CAA section 403(f), the House bill did not state that an allowance did not constitute a property right. Section 403(f) of the Senate bill that was considered, along with the House bill, in conference committee had language different than both CAA section 403(f) and the House bill and stated that ''allowances may be limited, revoked or otherwise modified in accordance with the provisions of this title or other authority of the Administrator'' and that an allowance ''does not constitute a property right.'' *Legis. Hist. of CAAA,* Vol. III at 4598. While the scope of the reference to the ''United States'' in CAA section 403(f) is not clear, EPA maintains that the term is clearly broad enough to include the Administrator. Moreover, even if the term were considered ambiguous with regard to the Administrator, EPA believes that interpreting the term to include the Administrator is reasonable. Specifically, EPA maintains that, by eliminating the explicit House bill language that required Congressional action and including the general reference to the ''United States'' and the ''not a property right'' language, CAA section 403(f)

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Therefore, EPA maintains that it has the authority to establish a new cap and trade program in accordance with section 110(a)(2)(D) that requires: the holding of title IV allowances under a more limited authorization (*i.e.*, 2 or 2.86 allowances per ton of emissions) by sources in States participating in the new program; and the termination of the authorization through retirement under the new program and the Acid Rain Program of those title IV allowances used to meet the allowance-holding requirement of the new program.

Commenters' Arguments Based on Title IV

The commenters claiming that EPA is barred by title IV from requiring use of title IV allowances at a reduced tonnage authorization in a new cap and trade program rely on the above-noted provision in section 402(3) stating that an allowance is an authorization to emit one ton of SO_2. However, this provision does not bar EPA from requiring either: use of title IV allowances in a new cap and trade program under a different title of the CAA at a reduced tonnage authorization; or retirement in this new program and the Acid Rain Program of allowances used in this manner.

At the outset, it should be noted that the CAIR model SO_2 cap and trade program does not change the tonnage authorization of individual title IV allowances for purposes of the Acid Rain Program until such an allowance is used to meet the allowance-holding requirement of the CAIR SO_2 program. The authorization provided by each title IV allowance for a source to emit one ton of SO_2 emissions, as well as the requirement that each source hold title IV allowances covering annual SO_2 emissions, continue to be in effect in the Acid Rain Program whether or not the source is also covered by the CAIR SO_2 program. In fact, the Acid Rain Program regulations continue to reflect both this tonnage authorization and this allowance-holding requirement.[138] See final revisions to 40 CFR § 73.35 adopted in today's action. Moreover, the CAIR model SO_2 cap and trade rule coordinates the determinations—made by EPA for sources subject to both title IV and the CAIR—of compliance with the title IV and CAIR allowance-holding requirements so that such determinations are made in a multi-step, end-of-year process of comparing allowances held and emissions. First, EPA determines whether the source holds sufficient title IV allowances to comply with the one-allowance-per-ton-of-emissions requirement in the Acid Rain Program as provided in § 73.35; and subsequently EPA determines whether the source holds the additional title IV allowances that, when added to those held for Acid Rain Program compliance, are sufficient to meet the CAIR allowance-holding requirement. Violations of the Acid Rain allowance-holding requirement will result in imposition of the penalty for excess emissions (*i.e.*, the one-allowance offset plus $2,000 (inflation-adjusted) per ton of excess emissions) under CAA section 411 and §§ 73.35(d) and 77.4. *See* final § 96.254(b)(1) adopted in today's action. Thus, the Acid Rain allowance-holding requirement continues as a separate requirement and reflects the one-allowance-per-ton-of-emissions authorization under section 402(3).[139]

In contrast with the one-allowance-per-ton-of-emissions requirement under the Acid Rain Program, the CAIR SO_2 cap and trade program requires each source generally to hold 2 or 2.86 Acid Rain allowances for each ton of SO_2 emissions. Contrary to the commenters' claim, this CAIR allowance-holding requirement is not barred by the definition of the term "allowance" in section 402(3). While section 402(3) defines the term "allowance" as an authorization to emit one ton of SO_2, this provision expressly applies the definition to the term "[a]s used in this title [IV]" and therefore does not apply to the treatment of title IV allowances in a different program under a different title of the CAA. Moreover, as noted above, section 403(f) allows EPA to limit (or terminate) the authorization to emit that an allowance otherwise provides under section 402(3). Consequently, the allowance definition in section 402(3) does not bar the treatment of a title IV allowance as authorizing less than one ton of SO_2 emissions under the CAIR SO_2 cap and trade program established under title I.[140]

Once a title IV allowance is used to meet the more stringent allowance-holding requirement in the CAIR SO_2 program, that allowance is deducted from the source's allowance tracking system account and cannot be used again, either in the CAIR SO_2 program or the Acid Rain Program. As noted above, EPA has the authority under section 403(f) to require this termination of such a title IV allowance's tonnage authorization for purposes of the Acid Rain Program.

In addition to referencing section 402(3) to support claims that EPA is barred from adopting the CAIR model cap and trade program provisions on the use of title IV allowances, the commenters rely on other title IV provisions that they characterize as setting a "title IV cap" on SO_2 emissions. Stating that the requirement to use title IV allowances in the CAIR model SO_2 cap and trade program has the effect of reducing the "title IV cap," these commenters indicate, with little explanation, that such requirement is unlawful. In mentioning the title IV cap, the commenters are apparently referring to the fact that section 403(a)(1) (requiring allowance allocations resulting in emissions not exceeding 8.90 million tons of SO_2) and section 405(a)(3) (requiring additional allocations of 50,000 allowances) require EPA to allocate annually, starting in 2010, a total amount of allowances authorizing no more than 8.95 million tons of SO_2 emissions. The commenters' argument about how the CAIR model SO_2 cap and trade program effectively reduces the "title IV cap" appears to be that elimination of the ability to use, in the Acid Rain Program, title IV allowances that will be used for compliance in the CAIR model SO_2 cap and trade program has the effect of reducing the annual 8.95 million ton cap on SO_2 emissions. This effective reduction of the "title IV cap" seems to occur when title IV allowances are used in the CAIR SO_2 trading program with a reduced tonnage authorization so that more title IV allowances are deducted per ton of emissions than would be deducted for compliance with the Acid

essentially adopted the Senate's approach and allows the United States—either through Congressional or administrative (*i.e.*, EPA) action—to terminate or limit the allowance authorization. *See Legis. Hist. of CAAA,* Vol. I at 754, 1034, and 1084 (Oct. 27, 2000 floor statements of Sen. Symms, Sen. Baucus, and Sen. McClure indicating EPA has authority to take such action); *but see* Cong. Rec. at E 3672 (Nov. 1, 2000)(extension of remarks of Cong. Oxley indicating that only Congress has such authority).

[138] As discussed below, today's action revises the Acid Rain Program regulations to provide for source-based, instead of unit-based, compliance with the allowance-holding requirement. These revisions are adopted for reasons independent of the adoption of the CAIR model SO_2 cap and trade program, as well as to facilitate the coordination of these two SO_2 trading programs.

[139] The commenters' assertion that the sources in a State that does not participate in the CAIR SO_2 cap and trade program will be cut off from the Acid Rain cap and trade program is incorrect on its face. Such a source will continue to be subject to the allowance-holding requirement and the compliance process in § 73.35 and will not be subject to the allowance-holding requirement and the compliance process in the CAIR model SO_2 cap and trade rule.

[140] The commenters also seem to argue that the allowance definition itself bars EPA from requiring use of Acid Rain allowances in the CAIR SO_2 trading program even on a one-allowance-per-ton-of-emissions basis. However, as noted above, the definition is silent on whether title IV allowances may or may not be used outside the Acid Rain Program.

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Rain Program.[141] The commenters claim that such a reduction in the 8.95 million ton cap is contrary to title IV.

In asserting an overarching principle that EPA is barred from adopting any requirement that would have the effect of reducing the 8.95 million ton cap under title IV, the commenters do not point to any specific statutory provision in support. The EPA maintains that not only are there no such supporting provisions, but also certain title IV provisions contradict this purported principle. Specifically, while sections 403 and 405 require annual allowance allocations authorizing no more than 8.95 million tons of emissions, section 403(f) provides, as noted above, that EPA may terminate or limit the one-allowance-per-ton-of-emissions authorization for a title IV allowance.[142] Because any termination or limitation of the tonnage authorization provided by a title IV allowance for purposes of the Acid Rain Program would have the effect of reducing the total tonnage of emissions allowed by the allowance allocations (i.e., the 8.95 million ton cap) under sections 403 and 405, the commenters' claim that EPA is barred from adopting any provision that has such an effect is wrong on its face.

Commenters' Argument Based on Clean Air Markets Group Case

The commenters also state that the CAIR model SO_2 cap and trade program is unlawful under the court's holding in *Clean Air Markets Group* v. Pataki, 338 F.3d 82 (2d Cir. 2003). According to the commenters, the required use of title IV allowances in the CAIR SO_2 program constitutes an unlawful interference with the operation of the interstate title IV SO_2 trading program, presumably similar to the unlawful interference found by the court in *Clean Air Markets Group*. However, the commenters provide little explanation of how such use of title IV allowances (with or without a reduced tonnage authorization) purportedly interferes with interstate operation of the Acid Rain Program and how the holding in *Clean Air Markets Group* applies to the CAIR SO_2 program.

In *Clean Air Markets Group,* the Court reviewed a State law that imposed a monetary assessment on any title IV allowance sold by a New York utility to a utility in any of 14 specified States or subsequently transferred to such a utility, with the assessment equaling the proceeds received in the allowance sale. The law also required that each allowance sold include a covenant barring subsequent transfer of the allowance to a utility in any of those States. The Court held that the State law was pre-empted by title IV because the State law impermissibly interfered with the method chosen by Congress in title IV to reduce utilities' SO_2 emissions, *i.e.*, the opportunity for nationwide trading of title IV allowances. *Id.* at 87–88. In particular, the Court found that the assessment of 100 percent of sale proceeds ''effectively bans'' sales of any allowance by New York utilities to utilities in the specified States and that the restrictive covenant ''indisputedly decreases'' the value of the allowances. *Id.* at 88.

The EPA maintains that today's action is distinguishable from the facts and holding in *Clean Air Markets Group*. In particular, EPA believes that the exercise of its explicit authority under section 403(f) to limit the tonnage authorization of a title IV allowance in the CAIR SO_2 cap and trade program and to terminate the tonnage authorization in the Acid Rain Program once the allowance is used in the CAIR SO_2 program is consistent with—and necessary to preserve—the operation of the Acid Rain Program. Therefore, EPA concludes that its approach of limiting and terminating of the tonnage authorization of title IV allowances does not impermissibly interfere with the interstate operation of the Acid Rain Program and is reasonable.

Unlike the circumstances in *Clean Air Markets Group,* under EPA's approach in today's action, each title IV allowance is freely transferable nationwide unless and until a source uses the allowance to meet the allowance-holding requirements of the CAIR SO_2 program, at which time the allowance is deducted from the source's allowance tracking system account and retired for purposes of both the CAIR SO_2 program and the Acid Rain Program. Further, EPA expects that the ability to use title IV allowances to meet the more stringent emission limitation under the CAIR SO_2 program to maintain or increase (not decrease) the value of each title IV allowance, until the allowance is used to meet the CAIR SO_2 program allowance-holding requirement and is retired.

Of course, this retirement of title IV allowances once they are used to meet the CAIR allowance-holding requirement means that they cannot thereafter be transferred to any person or be used again, *e.g.*, to meet the Acid Rain Program allowance-holding requirement. As noted by the Court in *Clean Air Markets Group,* section 403(b) provides that title IV allowances ''may be transferred among designated representatives of owners or operators of affected sources under [title IV] and any other person who holds such allowances, as provided by the allowance system regulations'' promulgated by EPA.[143] 42 U.S.C. 7651b(b). Moreover, section 403(d)(1) requires that the allowance system regulations ''specify all necessary procedures and requirements for an orderly and competitive functioning of the allowance system.'' 42 U.S.C. 7651b(d). In the context of these statutory requirements, EPA maintains that, on balance, the retirement of title IV allowances used for compliance in the CAIR model SO_2 cap and trade program does not constitute impermissible interference with the interstate operation of the Acid Rain Program, but rather is consistent with, and necessary to preserve, the operation of the Acid Rain Program.

As noted above, the imposition of an SO_2 emission limitation (such as in today's action) that is significantly more stringent than the one under title IV and covers most of the sources and emissions covered by title IV—but without addressing the impact on the Acid Rain Program—would likely have several adverse consequences. These adverse consequences would be: A significant excess of title IV allowances; a collapse of the price of title IV allowances; disruption of the title IV allowance market and the title IV SO_2 cap and trade system; and potential SO_2 emission increases, particularly in States outside the CAIR SO_2 region. The EPA modeling indicates that, in 2010, EGU SO_2 emissions in States not affected by the CAIR SO_2 program would increase by about 260,000 tons (or about 29 percent of the approximately 0.9 million tons of SO_2 emissions projected for the non-CAIR SO_2 region in 2010) in the absence of an approach for addressing the impact of the CAIR SO_2 program on title IV. This

[141] Similarly, to the extent title IV allowances are used in the CAIR SO_2 trading program by non-Acid Rain sources, the ''title IV cap'' seems to be effectively reduced because more allowances are used in the CAIR SO_2 trading program and effectively removed from use in the Acid Rain Program.

[142] In light of this provision, the statement in the NPR (particularly as it is interpreted by the commenters) that EPA lacks authority to tighten the requirements of title IV (69 FR 4618, col. 1) is overly broad and is not repeated or adopted in today's preamble.

[143] While section 403(b) (as well as section 403(d)) refer specifically to the allowance system regulations required to be promulgated by the EPA Administrator within 18 months of November 15, 1990 (the enactment date of the CAA), the EPA Administrator has authority under section 301 to amend such regulations ''as necessary to carry out his functions under [the CAA].'' 42 U.S.C. 7601.

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is because, with the imposition of the more stringent CAIR SO_2 emission limitation in the CAIR SO_2 region, this more stringent limitation becomes the binding limitation for sources in that region. These CAIR SO_2 sources must comply with, and cannot use title IV allowances to exceed, the CAIR SO_2 emission limitation. Consequently, the portion of the title IV allowances that equals the difference between the CAIR and the title IV emission limitations is excess and would be available for use only by Acid Rain sources that are outside the CAIR SO_2 region.

This excess amount of title IV allowances is potentially very significant. Today's action requires that the States in the CAIR SO_2 region achieve an amount of SO_2 emission reductions in 2010 and 2015 equal to 50 percent and 65 percent, respectively, of the amount of title IV allowances (about 7.3 million allowances out of the total nationwide allocation of 8.95 million allowances) allocated to the units in the CAIR SO_2 region. If the States achieve all the required CAIR SO_2 reductions through emission reductions by EGUs (which are largely the same units that are subject to the Acid Rain Program) and if EGUs held only one title IV allowance for each ton of SO_2 emissions as required in the Acid Rain Program, the amount of surplus allowances allocated to the States in the CAIR SO_2 region would be about 3.65 million allowances and 4.75 million allowances, respectively in 2010 and 2015.[144] Moreover, the vast majority of EGUs nationwide (about 90 percent) and of EGU SO_2 emissions nationwide (about 90 percent) are covered by the CAIR SO_2 program. The net result would be a large surplus of title IV allowances that would not be usable in the CAIR SO_2 region and would be usable only by the small subset of EGUs (about 10 percent) located in non-CAIR SO_2 region States. Looking at the nation as a whole (both CAIR and non-CAIR SO_2 States) in 2010, there would be total allocations in the Acid Rain Program of 8.95 million title IV allowances but, according to EPA modeling and analysis of the CAIR without a requirement to retire surplus title IV allowances, total projected SO_2 emissions for EGUs of only about 4.8 million tons.[145] Based on the principles of supply and demand, EPA concludes that, with the amount of allowances allocated nation wide exceeding SO_2 emissions for EGUs nationwide in 2010 by about 86 percent (*i.e.*, 8.95 million allowances minus 4.8 million tons divided by 4.8 million tons), the value of title IV allowances would fall to zero, and all but 260,000 of the surplus allowances would have no market and so, as a practical matter, would not be transferable.

The EPA notes that this effect on allowances would occur no matter how the State implements the more stringent SO_2 emission limitation required under the CAIR, *e.g.*, whether implementation is through a new cap and trade program (like in the model rule) or through a fixed (command and control) tonnage emission limit imposed on each individual source. Consequently, the alternatives faced by EPA are either: (1) To establish a CAIR model cap and trade program (or allow States to use another means of achieving CAIR SO_2 emissions reductions) that does not retire the 3.65 million surplus allowances and that results in the devaluation of all title IV allowances to zero and the effective non-transferability of all but 260,000 of the 3.65 million surplus allowances in 2010; or, as provided in today's action, (2) to adopt a CAIR SO_2 model cap and trade program (or another means of achieving reductions) that retires the 3.65 million surplus allowances and that results in the non-transferability of the entire 3.65 million surplus of title IV allowances and ensures the remaining, unused title IV allowances have market value. Thus, with regard to the impact on the transferability of title IV allowances, EPA's decision to adopt the second alternative of retiring the surplus allowances adversely affects the transferability of only a relatively small amount (260,000 out of 8.95 million per year) of allowances, as compared to the amount of allowances whose transferability would be adversely affected under the first alternative.

Moreover, with the total collapse of the title IV allowance price in the Acid Rain Program, the nationwide cap and trade system under title IV—which would be the binding cap and trade system only for sources in the States outside the CAIR SO_2 region—would lose all efficacy. The title IV cap and trade system operates by: Making owners of sources pay for the authorization to emit SO_2 by surrendering, to EPA, allowances that have a market value; and by allowing owners (*e.g.*, those who choose to reduce emissions) to sell unused allowances. Whether the sources' allowances were originally allocated to the sources or were purchased, the owners must decide the extent to which it is more efficient to give up the market value of such allowances or to reduce emissions. If title IV allowances were to have no market value, the title IV cap and trade system would no longer affect the choice of whether to emit or to reduce emissions.[146]

The EPA maintains that such a result is contrary to Congressional intent. The purposes of title IV include not only reductions of annual SO_2 emissions from 1980 levels, but also the encouragement of ''energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this title, for reducing air pollution and other adverse impacts of energy production and use.'' 42 U.S.C. 7651(b). Reflecting these purposes, Congress required EPA to promulgate allowance system regulations for the Acid Rain Program that would promote ''an orderly and competitive functioning of the allowance system.'' 42 U.S.C. 7651b(d)(1). *See* Sen. Rep. No. 101–228, 101st Cong., 1st Sess. at 320 (explaining that ''the allowance system is intended to maximize the economic efficiency of the program both to minimize costs and to create incentives for aggressive and innovative efforts to control pollution''). As discussed above, if title IV allowances were to have no market value, the cap and trade system under title IV would no longer affect owners' decisions on whether to emit or to control emissions and so would no longer provide encouragement (*e.g.*,

[144] The surpluses for 2010 and 2015 respectively are calculated as: 7.3 million allowances minus ((100 percent minus the percentage reduction requirement for the year) times 7.3 million allowances).

[145] The 4.8 million ton figure is the sum of: 3.65 million tons of emissions (equal to the tonnage equivalent of the allowance allocations in the CAIR SO_2 region); plus about 0.9 million tons of emissions in the non-CAIR SO_2 region with the retirement of surplus title IV allowances; plus 260,000 tons of increased non-CAIR SO_2 region emissions if the surplus title IV allowances are not retired.

[146] *See* Sen. Rep. No. 101–228, 101st Cong., 1st Sess. at 324 (Dec. 20, 1989) (stating that ''[a]llowances are intended to function like a currency that is sufficiently valuable to stimulate efforts to acquire it through innovative and aggressive efforts to reduce emissions more than required'' and that, in the event of ''inflation in the currency,'' the incentives to ''reduce pollution * * * will be seriously weakened.'' In the instant case, without a requirement to retire excess title IV allowances, the currency would be inflated to a value of zero. *See also Legis. Hist. of CAAA*, Vol. I at 1033 (Oct. 27, 1990 floor statement of Sen. Baucus explaining that ''[s]ince units can gain cash revenues from the sale of allowances they do not use, they will have a financial incentive both to make greater-than-required reductions and/or reductions earlier than required'' and that ''incentives created by the allowance market should stimulate innovations in the technologies and strategies used to reduce emissions'' including energy efficiency).

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incentives for innovation) for avoidance or reduction of SO_2 emissions.[147]

In addition, EPA is concerned that such disruption of the title IV allowance market and the title IV SO_2 cap and trade system would significantly erode confidence in cap and trade programs in general and the CAIR model cap and trade programs in particular. As noted above, under the Acid Rain Program, companies have made billions of dollars of investments in emission controls in order to be able to sell excess title IV allowances and in purchasing title IV allowances for future compliance (*e.g.*, under annual, 1-day allowance auctions held by EPA, one as recently as March 22, 2004 when title IV allowances were purchased for about $50 million). While in a market-based program like the Acid Rain Program, investments are necessarily subject to the vagaries of the market, EPA believes that it should try, to the extent possible consistent with statutory requirements, to avoid taking administrative actions that would cause such extensive disruption of the Acid Rain Program. Allowing such disruption to occur could significantly reduce the willingness of owners of sources in new cap and trade programs to invest in measures that would result in excess allowances for sale or to purchase allowances for compliance. To the extent owners would ignore the allowance-trading option and simply control emissions to the level equal to their source's allocations, this would obviate the incentives for innovation, and hamper realization of the potential for cost savings, that would otherwise be provided by new cap and trade programs (such as the CAIR model cap and trade programs).

Finally, as noted above, such disruption of the Acid Rain Program would potentially result in significantly increased SO_2 emissions (about 29 percent in 2010) in States covered by the Acid Rain Program but outside the CAIR SO_2 region.[148] This would have the effect of reversing, at least in part, the beneficial effect that the Acid Rain Program has had on SO_2 emissions in those States, even though the overall goal of nationwide SO_2 emissions reductions would still be met. *See* 42 U.S.C. (a)(1) (Congressional finding that ''the presence of acidic compounds and their precursors in the atmosphere and in deposition from the atmosphere represents a threat to natural resources, ecosystems, materials, visibility, and public health'').

In light of these considerations,[149] EPA concludes, on balance, that structuring the CAIR model SO_2 cap and trade program in a way that avoids such extensive disruption of the Acid Rain Program (*i.e.*, by requiring retirement from the Acid Rain Program of title IV allowances used for compliance in the CAIR SO_2 program) does not constitute impermissible interference with the interstate operation of the Acid Rain Program. Rather, this approach in the model SO_2 cap and trade rule is consistent with, and preserves, such operation—while providing States a tool for imposing the more stringent SO_2 emission limitations required under title I—and is a reasonable exercise of EPA's authority under section 403(f) to terminate or limit the tonnage authorization of title IV allowances.

2. Legal Authority for Requiring Retirement of Excess Title IV Allowances if State Does Not Use CAIR Model SO_2 Cap and Trade Program

As discussed above, a State has the additional options of achieving the SO_2 emissions reductions required by today's actions through: EGU emission reductions only but without using the model SO_2 cap and trade rule; some EGU and some non-EGU emissions reductions; or non-EGU reductions only. The requirement to retire excess title IV allowances applies only in the first and second of these three additional options. The State must retire an amount of title IV allowances equal to the total amount of title IV allowances allocated to units in the State minus the amount of allowances equivalent to the tonnage cap set by the State on EGUs' SO_2 emissions and can choose what mechanism to use to achieve such retirement. The EPA has the authority to require that the State include in its SIP a mechanism for retiring the excess title IV allowances that will result under these two options.

As discussed above, EPA has the authority under section 403(f) to terminate or limit the authorization to emit otherwise provided by a title IV allowance. Specifically, EPA has the authority to: require that any EGU SO_2 emission reduction program, chosen by a State to meet (in full or in part) the requirements of section 110(a)(2)(D), include provisions for retiring excess title IV allowances resulting from the implementation of the more stringent emission reduction requirement under the State program; and to require that such retired title IV allowances cannot be used in the Acid Rain Program. As discussed above, the commenters' claims that such a retirement requirement is barred by title IV (relying on, *e.g.*, the section 402(3) definition of ''allowance'' and on the ''title IV cap'') lack merit. Also, for the reasons discussed above, the retirement requirement is not unlawful under *Clean Air Markets Group* and is a reasonable exercise of EPA's authority under section 403(f) to terminate or limit the tonnage authorization of title IV allowances.

Some commenters also claim that the retirement requirement unlawfully constrains the States' authority to determine in the first instance the control measures to use in meeting emission reduction requirements necessary to comply with section 110(a)(2)(D). According to the commenters, since only EGUs are subject to title IV, the requirement to retire title IV allowances is in effect a mandate that the State control EGU emissions.

However, EPA is imposing the requirement for a State mechanism to retire title IV allowances only if the State decides in the first instance to require any EGU SO_2 emissions reductions to meet the emission reduction requirements under today's action. A State that decides not to require any EGU SO_2 emissions reductions for this purpose is not required to retire title IV allowances. Further, the amount of the required allowance retirement is limited to the amount of EGU SO_2 emissions reductions that the State decides in the first instance to require from EGUs (*i.e.*, the total title IV allowance allocations in the State minus the tonnage amount of the cap set by the State for EGUs' SO_2 emissions). In short, the allowance retirement requirement echoes the State's decision in the first instance concerning the amount of SO_2 emissions reductions to require from EGUs in the State. The EPA simply requires the State to implement the State's EGU–SO_2-emission-reduction-requirement decision in a manner that avoids the otherwise likely, extreme disruption of the title IV SO_2 cap and trade system that is described above. Further, the

[147] While the title IV cap and trade system could be replaced by a new CAIR SO_2 cap and trade system that did not address the problems caused by surplus title IV allowance, that new cap and trade system would not be nationwide like the title IV cap and trade system and so would not cover sources outside the CAIR SO_2 region.

[148] The EPA notes that the potential for increased emissions *within* the CAIR SO_2 region would occur before the implementation of the CAIR SO_2 program and is addressed by allowing pre-2010 banked title IV allowances to be used to meet the CAIR allowance holding requirement beginning in 2010.

[149] While the potential for increased emissions outside the CAIR SO_2 region supports EPA's conclusion, EPA maintains that, even in the absence of any such increase, the other considerations discussed above are sufficient to justify the conclusion that the retirement of title IV allowances does not impermissibly interfere with the Acid Rain Program and is reasonable.

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State may choose what mechanism to include in its SIP revision for achieving the required allowance retirement, and EPA will review the effectiveness of the mechanism in achieving such retirement, and approve and adopt the mechanism if appropriate, in an EPA rulemaking concerning the SIP revision. Therefore, EPA concludes that the allowance-retirement requirement is lawful and is a reasonable condition for EPA approval of those State SIPs that require EGU SO_2 emission reductions without using the CAIR model SO_2 trading program.

The EPA notes that the requirement to retire excess title IV allowances—where a State adopts the CAIR model SO_2 trading program or where a State SIP obtains EGU emissions reductions through some other means—is reflected in provisions in both the proposed rules in the SNPR (*i.e.*, in proposed §§ 51.124(p) and 96.254(b)) and in the final rules adopted by today's action (*i.e.*, in final §§ 51.124(p) and 96.254(b)). In reviewing the proposed rules in light of the comments received, EPA has concluded that, for consistency and clarity, the Acid Rain Program regulations should also reference this same retirement requirement. Consequently, today's action adds a new paragraph (a)(3) to § 73.35 of the Acid Rain Program regulations that reiterates the requirement—addressed in the preamble and regulations in both the SNPR and today's action—that title IV allowances previously used to meet the allowance-holding requirement in the CAIR model trading program in § 96.254(b) or otherwise retired in accordance with § 51.124(p) cannot be used to meet the allowance-holding requirement in the Acid Rain Program. Additional revisions of the Acid Rain Program regulations are discussed below.

3. Revisions to Acid Rain Regulations

In the SNPR, EPA proposed to revise the Acid Rain Program regulations, effective July 1, 2005, to implement the allowance-holding requirement on a source-by-source, rather than on a unit-by-unit, basis. Instead of requiring each unit to hold an amount of allowances in its Allowance Tracking System account (as of the allowance transfer deadline) at least equal to the tonnage of SO_2 emissions for the unit in the preceding calendar year, the proposal required each source to hold an amount of allowances in its Allowance Tracking System account at least equal to the tonnage of SO_2 emissions for all affected units at the source for such calendar year. Because language reflecting or referencing the unit-by-unit compliance approach is included in many provisions of the Acid Rain Program regulations, a significant number of proposed rule revisions were necessary to implement source-by-source allowance holding.

In today's final rule, EPA is adopting, with minor modifications, the proposed rule revisions implementing source-by-source compliance with the allowance-holding requirement. As explained in detail in the SNPR (69 FR 32698–32701), EPA finds that: Title IV is ambiguous with regard to whether unit-by-unit compliance is required and so EPA has discretion in this matter; it is important to provide additional compliance flexibility by allowing a unit at a source to use allowances from any other unit at the same source; and many other, non-allowance-holding provisions of title IV evidence a unit-by-unit orientation. Further, as discussed in the SNPR, EPA concludes that the adoption of source-level compliance reasonably balances these considerations. In balancing these considerations, EPA also concludes that company-level compliance is not appropriate because it represents too much of a deviation from the unit-by-unit orientation in the non-allowance-holding provisions of title IV and is likely to require much more dramatic changes in the operation of the Acid Rain Program. *See* 69 FR 32699–700. It is important to note that the final rule revisions, like the proposed revisions, change only the allowance-holding requirement and not the emissions monitoring and reporting requirements, which continue to be applied unit by unit.

In today's action, EPA is making the source-level-compliance rule revisions effective July 1, 2006, which is 1 year later than proposed. The shift from unit-level to source-level compliance will require software changes and testing to ensure that the Allowance Tracking System operates properly. Currently, EPA is in the process of conducting a general review and re-engineering of the Allowance Tracking System and Emissions Tracking System and anticipates completing the process in 2006. The process of shifting the Allowance Tracking System to source-level compliance will be much more efficient and less likely to have adverse results on the system if the shift is coordinated with the general review and re-engineering and therefore implemented starting July 1, 2006. Further, as discussed below, this delay of implementation for 1 additional year will give owners additional time to make changes that they determine are necessary in order to adapt to source-level compliance.

Some commenters support the shift to source-by-source allowance holding, and some oppose the change. One commenter opposing the change claims that a source-by-source allowance-holding requirement is ''contrary to market-based principles.'' According to the commenter, market-based systems give operators the tools for achieving compliance through allowance transfers, but with source-level compliance the operators do not have to take any action to maintain sufficient allowances because EPA will move the allowances around for them.

The commenter's argument is based on an incorrect premise. Whether compliance is unit-by-unit or source-by-source, the owner or owners of the affected units at each source must take the same types of actions in order to comply with the applicable allowance-holding requirement. In particular, under source-level compliance, such owner or owners must reduce emissions, retain allowances allocated to such units, obtain additional allowances, or take a combination of these actions to ensure that the Allowance Tracking System account for the source holds enough allowances to cover the total emissions of the affected units at the source. The owner or owners also have the option of reducing emissions below allocations so that there are extra allowances available to hold for future use or sale. If the owner or owners do not have enough allowances to cover the emissions from the source, EPA will not move, on its own initiative, allowances into the source's compliance account from other sources' accounts or from general accounts, even if there are extra allowances in the other accounts. The only difference between the types of actions owners must take under the unit-level and source-level approaches is that, under unit-level compliance, the owners must transfer allowances from one unit at a source to a second unit at that source in order to use the first unit's allowances for compliance by the second unit while, under source-level compliance, any allowance held for compliance for the first unit can be used—without a transfer—for compliance by the second unit. This difference is reflected in the Allowance Tracking System, which, under the unit-level approach, includes a separate account for each unit and, under the source-level approach, includes a single account for all the affected units at a single source.

In summary, the mechanism, and the owners' responsibilities, for achieving

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compliance with the allowance-holding requirements are analogous under unit-by-unit and source-by-source compliance, except that, under source-by-source compliance, allowances need not be transferred among units at the same source. The EPA does not believe that the source-by-source approach is any less market-based than the unit-by-unit approach. Owners will still have the ability to reduce emissions or purchase or sell allowances and the responsibility to take actions (including the holding of extra allowances) to ensure they have enough allowances to cover emissions. Moreover, the market-price of allowances will still play a crucial role in owners' decisions on what actions to take. The EPA's adoption of source-by-source compliance preserves market-based principles, while reasonably balancing of the ambiguity of title IV, the need for additional compliance flexibility, and the unit-by-unit orientation of many provisions in title IV. *See* 69 FR 32699–700.

The commenter also argues that having a source-level allowance-holding requirement in the Acid Rain Program (and the CAIR model cap and trade program) is inconsistent with unit-level compliance in the NO_X SIP Call cap and trade program. However, other than pointing out this difference, the commenter fails to explain why the programs must be identical in this regard. Based on experience with the Acid Rain Program (as well as the NO_X SIP Call trading program), EPA concludes that a source-level allowance-holding requirement will result in a somewhat less complicated program and a reduced likelihood of inadvertent, minor errors, while achieving the program's environmental goals. *See* 69 FR 32699–700.

The commenter suggests that, instead of adopting source-level compliance, EPA revise the Acid Rain Program regulations to allow for source over-draft accounts, like those allowed in the NO_X SIP Call cap and trade program. Under the NO_X SIP Call program, each source may have a source over-draft account, in which may be held extra allowances that may be used for compliance by any affected unit at the source. However, EPA believes that source-level compliance is a better approach than unit-level compliance with over-draft accounts. Relatively few owners in the NO_X SIP Call cap and trade program actually put allowances in over-draft accounts, and achievement of compliance is made more complicated by the ability of all units at a source to draw on the over-draft account (if any allowances are put in it) but the inability of any unit to use extra allowances held instead by another unit at the source. Consequently, rather than adopting in the Acid Rain Program the unit-level approach with over-draft accounts, EPA is today adopting the source-level approach in the Acid Rain Program and may consider in the future, as appropriate, adopting the source-level approach in other programs using unit-level compliance.

One commenter states that EPA should revise the Acid Rain Program regulations to allow owners, each year, the option of choosing whether to use unit-level or source-level compliance. According to the commenter, significant investments have been made to monitor and report emissions and surrender allowances under the existing Acid Rain Program regulations, and shifting to source-level compliance will require substantial resources and time. The commenter also states that unit-based compliance should be retained as an option ''to accommodate joint ownership and other special arrangements that may not affect an entire facility.''

The EPA rejects the suggestion of allowing each owner the option, for each year and for each source, of choosing between unit-level and source-level compliance. Such an approach would significantly complicate the achievement by sources, and the determination by EPA, of compliance. The potential for error (*e.g.*, due to erroneous assumptions about whether unit-or source-level compliance would be applicable to a particular source for a particular year) on the part of owners or EPA would be significantly increased. Moreover, this complicated approach would result in inconsistent treatment from source to source and year-to-year. Further, the commenter provided only vague assertions about the benefits of unit-based compliance in certain circumstances and did not assert—much less show—that source-level compliance cannot be accommodated under those circumstances. The EPA maintains that the only reasonable options for the allowance-holding requirement in the Acid Rain Program are either generally requiring compliance by all sources each year on a unit-level basis (as in the existing regulations) or requiring compliance by all sources each year on a source-level basis (as in the proposed revisions to the regulations). For the reasons discussed above, EPA believes that source-level compliance for the allowance-holding requirement is preferable. By postponing until July 1, 2006 the effective date of the rule revisions shifting to source-level compliance (with the result that 2006 is the first year of source-level compliance), EPA is providing owners a reasonable amount of time to make any necessary adjustments, such as those claimed by the commenter. Further, as noted above, the rule revisions change only the allowance-holding requirement and not the emissions monitoring and reporting requirements. This should limit the scope of adjustments necessary for owners to implement source-level compliance and will preserve the availability of reliable, unit-level emissions data.

Because unit-level compliance is reflected throughout the Acid Rain Program regulations, numerous revisions of the regulations are necessary to implement source-level compliance. (None of these changes are to the emissions monitoring and reporting provisions in part 75 since monitoring and reporting continue to be on a unit basis.) One commenter requested that EPA provide ''more in-depth detail'' on the proposed revisions. However, in the SNPR, EPA described the types of, and reasons for, revisions that are necessary for source-level compliance (69 FR 32700–01) and set forth all of the specific, proposed changes (69 FR 3273–41). Moreover, no commenters stated that they did not understand any specific, proposed revision or the reason for any specific revision. The EPA notes that in reviewing the proposed Acid Rain rule revisions in light of the comments, EPA found some additional references in the Acid Rain rule to unit-level compliance that should be revised to reflect source-level compliance. In today's action, EPA is adopting revisions of these additional references (*e.g.*, changing references to a ''unit's account'' or a ''unit account'' to a source's ''compliance account'') that are analogous to the revisions specifically identified in the SNPR.[150]

Another commenter opposed the rule revisions implementing source-level compliance on several other grounds. The commenter claims, without citing any statutory support, that the Acid Rain Program is based on ''control of emissions at the unit level'' so that, in the event of excess emissions, the ''source as a whole would not be punished'' and ''corrective action could take place'' at the particular unit. According to the commenter, source-level compliance will: Make it harder to determine which unit caused excess emissions; make the existing Acid Rain

[150] This approach is consistent with the SNPR, where EPA proposed to convert all references, including any initially missed in the SNPR, from unit- to source-level compliance (69 FR 32700).

permits meaningless; make the individual unit allowance allocations meaningless; and cause confusion over which units at a source are affected units.

While there are many non-allowance-holding provisions in title IV that have a unit-by-unit orientation, EPA disagrees with the commenter's basic assertion that the purpose of the Acid Rain Program is to control emissions on a unit-by-unit basis and that there is a need to ''distinguish'' the compliance of each individual unit. The provisions concerning application of the allowance-holding requirement are ambiguous as to whether EPA must implement the requirement on a unit-level or a source-level, and the environmental benefits of the Acid Rain Program will still be realized with source-level compliance. *See* 69 FR 32699–700. Further, while EPA will determine compliance on a source-by-source basis, nothing in the regulations prevents owners (*e.g.*, owners of units at sources with multiple units and multiple owners or owners of units with multiple owners and exhausting through a common stack) from determining by agreement which owners will bear any excess emissions penalties that occur at the plant and have to take correction actions. Indeed, owners are likely to already have these types of agreements in cases of units or sources with multiple owners. This is because the Acid Rain Program regulations already allow a unit at a multi-unit source to use some allowances from other units at the source (albeit to cover most but not all of the potential excess emissions) and already allow one unit exhausting from a common stack to use allowances from another unit at that stack (without any limitation on such use). *See* 40 CFR 73.35(b)(3) and (e). In addition, while the Acid Rain permits will have to be revised in the future to reflect source-level compliance, today's rule does not make source-level compliance effective until 2006. Permits will not have to be revised until around the end of 2006, which should provide States a reasonable opportunity to amend the permits. Contrary to the claims of the commenter, source-level compliance does not make the unit-by-unit allocations meaningless; the unit-by-unit allocations (set forth in Table 2 of § 72.10) will determine the amount of allocations reflected in each Allowance Tracking System source account, which amount will equal the sum of the allocations for all affected units at the source. Finally, the commenter failed to explain how the source-level allowance-holding requirement could cause ''confusion'' over which units are affected units. This source-level requirement does not change the applicability provisions, which are still applied unit by unit.

As discussed in the SNPR, EPA proposed—in addition to the rule revisions to implement source-level compliance—other revisions of the Acid Rain Program regulations in order to facilitate coordination of the Acid Rain Program and the CAIR SO_2 cap and trade program. These additional revisions were described and explained in the SNPR (69 FR 32701). The EPA is adopting these revisions for the reasons in the SNPR, as amplified below. Most of these revisions are supported, or not opposed, by commenters, but some commenters objected to certain revisions.

For example, EPA noted that it had recently changed the ''cogeneration unit'' definition in § 72.2 in June 2002 (67 FR 40394, 40420; June 12, 2002). The original definition in § 72.2 had been used since the commencement of the Acid Rain Program. The only significant difference between the original and revised definitions is that the former refers to a unit ''having the equipment used to produce'' electricity and useful thermal energy through sequential use of energy, while the latter simply refers to a unit ''that produces'' electricity and useful thermal energy in that manner. The reason that EPA gave for revising the definition in June 2002 was to conform with the definition in the Section 126 rule. However, the Section 126 rule (and the NO_X SIP Call) did not actually specify a ''cogeneration unit'' definition. Consequently, there is no reason to use the June 2002 revised definition. Moreover, EPA is concerned that the change in the definition of ''cogeneration unit'' as of June 2002 may cause confusion or raise question about what units qualify for exemptions for ''cogeneration units'' from the Acid Rain Program. Under these circumstances, EPA concludes that the definition should be changed back to the original definition in § 72.2 and, in any event, intends to interpret the June 2002 revised definition as having the same meaning as the original definition. One commenter raised concerns that EPA did not provide any ''detailed analysis'' of the implications of changing the ''cogeneration unit'' definition. However, as discussed above, the change simply reinstates the definition that had been used in the Acid Rain Program from the initial promulgation of implementing regulations in 1993 until 2002. No commenter asserted that reverting to the longstanding, original definition would be disruptive.

Another Acid Rain Program rule revision proposed in the SNPR is the elimination of the requirement for owners and operators to submit an annual compliance certification report for each source. One commenter expressed concern, because the purpose of the annual certification is to ensure that the designated representative is ''aware and has assured the quality of the data'' being submitted to EPA. However, as noted in the SNPR, designated representatives must evidence such awareness and compliance by submitting, with each quarterly emissions report, a certification that the monitoring and reporting requirements under part 75 of the Acid Rain Program regulations have been met. *See* 40 CFR 75.64(c). Quarterly emissions reports are available on-line to the public and the States. In addition, owners and operators of sources subject to the Acid Rain Program must submit, under title V of the CAA, annual compliance certification reports concerning all CAA requirements (including Acid Rain Program requirements). Under these circumstances, EPA maintains that the separate Acid Rain Program annual compliance certification reports are duplicative and unnecessary. The EPA notes that it appears that few, if any, requests for copies of these Acid Rain Program reports have been made by States or any other persons since the commencement of the Acid Rain Program. Apparently, other certifications and submissions required of owners and operators have been sufficient for the purposes cited by the commenter.

The SNPR also included proposed revisions eliminating the requirement under the Acid Rain Program for a 1-day newspaper notice for designation of designated representatives and authorized account representatives. One commenter suggests that this notice should be replaced by a requirement to notify the State permitting authority. The EPA notes that information on designated representatives and authorized account representatives is already available to State permitting authorities through on-line access to the Allowance Tracking System. Moreover, EPA is in the process of developing, and anticipates establishing in the near future, the ability to send State permitting authorities (at their request) on-line notices of changes in designated representatives (who are also the authorized account representatives for affected sources' accounts).

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Other proposed Acid Rain Program rule revisions on which EPA received adverse comment are the removal of § 73.32 (prescribing the contents of an allowance account) and § 73.51 (prohibiting the transfer of allowances from a future year subaccount to a subaccount for an earlier year). Section 73.32 sets forth a rather self-evident list of information that must be recorded in an allowance account in the Allowance Tracking System, such as the name of the authorized account representative, the persons represented by the authorized account representative, and the transfers of allowances in and out of the account. This section also references information on compliance or current year subaccounts and future year subaccounts, as well as emissions information. As discussed in the SNPR, several items on the list of informational contents for allowance accounts are out-of-date in that they do not reflect how the electronic Allowance Tracking System operates or will operate in the near future. For example, the electronic Allowance Tracking System does not currently use or refer to subaccounts, which will continue to be unnecessary in the context of source-level compliance.[151] *See* 69 FR 32700–01. In addition, while § 73.32 states that emissions data are reflected in the Allowance Tracking System account, such data are currently available instead through the electronic Emissions Tracking System. Because the information list in § 73.32 contains either self-evident items or items that are out-of-date and because the NO_X Allowance Tracking System has been operating successfully even though the model NO_X Budget cap and trade rule and State cap and trade rules under the NO_X SIP Call lack a provision analogous to § 73.32, EPA is removing § 73.32. EPA notes that the removal of the section will not mean that the information contained in allowance accounts ''can be changed at will.'' The format for allowance accounts is set forth in the electronic Allowance Tracking System and implements the requirements in the Acid Rain Program regulations concerning the holding, transferring, recording, and deducting of allowances.

Section 73.51 prohibits the transfer of allowances from a future year subaccount to a subaccount for an earlier year. The removal of this section is consistent with the elimination throughout the rest of the Acid Rain Program regulations, as discussed in the SNPR (*id.*), of any references to such subaccounts. Further, the prohibition on using allowances allocated for a year to meet the allowance-holding requirement for a prior year is retained in other provisions of the Acid Rain Program regulations. Consequently, EPA is removing § 73.51.

C. How Does the Rule Interact With the Regional Haze Program?

This section discusses the relationship of the CAIR cap and trade program for EGUs with the regional haze program under sections 169A and 169B of the CAA, in particular the requirements for Best Available Retrofit Technology (BART) for certain source categories including EGUs. The legislative and regulatory background of the BART provisions were presented in some detail in the SNPR. (See 69 FR 32684, 32702–704, June 10, 2004). In brief, BART regulations consist of two components. The first, promulgated in 1980, addresses visibility impairment that can be ''reasonably attributed'' to a single source or small group of sources. (45 FR 80085; December 2, 1980, codified at 40 CFR 51.302). The second component addresses BART in relation to regional haze (visibility impairment caused by a multitude of broadly distributed sources) and was promulgated as part of the Regional Haze Rule. (64 FR 35714; July 1, 1999). Certain parts of the BART provisions in that rule were vacated by the U.S. Court of Appeals for the DC Circuit in *American Corn Growers et al.* v. *EPA,* 291 F.3d 1 (DC Cir., 2002). To address that decision, in May 2004, EPA proposed changes to the Regional Haze Rule and reproposed the Guidelines for BART Determinations (originally proposed in 2001) (69 FR 25185, May 5, 2004).

On February 18, 2005, the DC Circuit decided another case dealing with BART and a BART alternative program, *Center for Energy and Economic Development* v. *EPA*, No. 03–1222, (DC Cir. Feb. 18, 2005) (''*CEED*''). In this case, the court granted a petition challenging provisions of the regional haze rule governing the optional emissions trading program for certain western States and Tribes (the ''WRAP Annex Rule''). The holdings of the case are relevant to today's action in several respects.

Most importantly for purposes of the CAIR, *CEED* affirmed EPA's interpretation of CAA 169A(b)(2) as allowing for non-BART alternatives where those alternatives make greater progress than BART. (*CEED*, slip. op. at 13) (finding that EPA's interpretation of CAA 169(a)(2) as requiring BART only as necessary to make reasonable progress passes the two-pronged Chevron test).

The particular provisions involved in *CEED* applied, on an optional basis, only to nine western States[152] (none of which are in the CAIR region) and the Tribes therein. The provisions, contained in 40 CFR 51.309 (''section 309'') required among other things that States choosing to participate in a ''backstop''[153] cap and trade program must demonstrate that the emissions reductions under the program resulted in greater progress towards the national visibility goals than would BART. At issue was the particular methodology required for this demonstration. Specifically, EPA's rule required that visibility improvements under source-specific BART—the benchmark for comparison to the cap and trade program—must be calculated based on the application of BART controls to all sources subject to BART.[154] Although *American Corn Growers* had vacated this cumulative visibility approach in the context of determining BART for individual sources, EPA believed that it was still permissible to require this methodology in the context of a BART-alternative program. The DC Circuit in *CEED* held otherwise, stating: ''EPA cannot under § 309 require states to exceed invalid emission reductions (or, to put it more exactly, limit them to a § 309 alternative defined by an unlawful methodology).'' (*Id.* at 14).

Thus, *CEED* firmly established two principles: (1) The CAA allows States to substitute other programs for BART where the alternative achieves greater progress, and (2) EPA may not require States to evaluate visibility improvement on a cumulative basis as a condition for approval of a BART-alternative. The first principle validates EPA's proposal to allow the CAIR to substitute for BART. The second

[151] In reviewing the proposed Acid Rain Program rule revisions, EPA found some additional references to ''subaccounts'' that were not specifically noted in the SNPR. For consistency and clarity in the Acid Rain Program rules, EPA is adopting in today's action revisions (*e.g.,* chaning the term ''subaccount'' to ''compliance account'') of these additional references, which revisions are analogous to those specifically set forth in the SNPR. This approach is consistent with the SNPR, where EPA proposed to convert all references, including any initially missed in the SNPR, from subaccount to compliance account, (69 FR 32700).

[152] Arizona, California, Colorado, Oregon, Idaho, Nevada, New Mexico, Utah, and Wyoming.

[153] The trading program is referred to as a ''backstop'' because under the WRAP Annex, States have the opportunity to achieve specified emission milestones using voluntary measures, with the trading program coming into effect only if those milestones are exceeded.

[154] The methodology is prescribed in 40 CFR 51.308(e)(2) and incorporated into § 309 by reference at 40 CFR 51.309(f).

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principle is not at issue in the CAIR context, because EPA is not proposing to impose the cumulative visibility methodology upon States, nor to require States to treat the CAIR as having satisfied their BART obligations.

Nonetheless, EPA has determined that it is premature to make a final determination regarding the sufficiency of the CAIR as a BART alternative, primarily because (1) the guidelines for source-specific BART determinations, in response to *American Corn Growers* have not been finalized, and (2) there is now a need to revise the Regional Haze Rule and the guidelines for BART-alternative programs in response to *CEED*. The source-specific BART guidelines will be finalized on or before April 15, 2005, under a consent decree. The rule changes and revisions to the BART-alternative guidelines will be proposed soon thereafter.

Therefore, we are making no final determination in today's action with respect to BART. The EPA continues to believe, however, that the CAIR will result in greater progress in visibility improvement than BART, as explained below.

1. How Does This Rule Relate to Requirements for BART Under the Visibility Provisions of the CAA?

a. Supplemental Notice of Proposed Rulemaking

In the SNPR, we proposed that States which adopt the CAIR cap and trade program for SO_2 and NO_X would be allowed to treat the participation of EGUs in this program as a substitute for the application of BART controls for these pollutants to affected EGUs.[155] To give this option effect, we proposed an amendment to the Regional Haze Rule which would add a section at 40 CFR 51.308(e)(3), as follows:

(3) A State that opts to participate in the Clean Air Interstate Rule cap and trade program under part 96 AAA–EEE need not require affected BART-eligible EGUs to install, operate, and maintain BART. A State that chooses this option may also include provisions for a geographic enhancement to the program to address the requirement under § 51.302(c) related to BART for reasonably attributable impairment from the pollutants covered by the CAIR cap and trade program.

This proposal is consistent with currently existing provisions which allow States to develop cap and trade programs or other alternative measures in lieu of the application of BART on a source specific basis. (*See* 40 CFR 51.308(e)(2) and 64 FR 35714, 35741–35743, July 1, 1999). The proposal was based on the application of the proposed two-pronged test for whether an alternative to BART is ''better than BART'' which was proposed in the 2001 BART guidelines and reproposed without changes in our May, 2004 proposed guidelines for BART determinations (69 FR 25184, May 5, 2004).

Specifically, the re-proposed BART Guidelines provide that if the geographic distribution of emissions reductions is anticipated to be similar under both programs, the trading program (or other alternative measure) must be shown to achieve greater overall emissions reductions than the application of source-specific BART. If the trading program is anticipated to result in a different geographic distribution of emissions reductions than would source-specific BART, the trading program must be shown to result in no decline in visibility at any Class I area, and in an overall improvement in visibility on an average basis over all affected Class I areas (69 FR 25184, 25231). Because we had not yet determined whether there is a difference in the geographic distribution of emissions reductions between the CAIR and the application of source-specific BART in the CAIR region, we assessed the difference between the two programs by evaluating the visibility impacts of each program, using this proposed two-pronged test.

The emissions projections and air quality modeling used to demonstrate that the CAIR satisfies this proposed two-pronged test were presented in a document entitled Supplemental Air Quality Modeling Technical Support Document (TSD) for the Clean Air Interstate Rule (May 4, 2004). In brief, we found that the CAIR would not result in a degradation of visibility from current conditions at any Class I Area nationwide. Within the CAIR-affected States and New England, EPA found that the CAIR would produce greater visibility benefits—specifically, an average improvement of 2.0 deciviews, as compared to 1.0 for BART. The EPA also found that average visibility improvement for Class I areas nationwide would be 0.7 deciviews under the CAIR, compared to 0.4 deciviews under BART. The EPA noted in the SNPR and the TSD that because the emissions scenarios used in these analyses were developed for different purposes, the scenarios varied slightly from the scenarios which would be ideal for this test. The EPA committed to conduct additional analyses, and those analyses have now been done. The new modeling and results are discussed in more detail in section IX.C.2 below.

b. Comments and EPA's Responses

Several commenters argued that a categorical exclusion of sources from BART would violate the CAA, as interpreted by the U.S. Court of Appeals for the DC Circuit in *American Corn Growers* v. *EPA,* 291 F.3d 1, 2002, by illegally constraining the discretion Congress conferred to States in making BART determinations and by depriving States of an adequate opportunity to evaluate the emissions reductions in light of the BART requirement. Some States also expressed a desire to retain their discretion to require BART. Additionally, some commenters asserted that EPA could not offer an exemption to BART unless the conditions for exemptions provided by CAA 169A(c) are met, including a showing that the source in question will not, alone or in combination with other sources, emit any pollutant which may reasonably be anticipated to cause or contribute to impairment at any Class I area, and the concurrence of the appropriate Federal Land Manager with the exemption determination.

The EPA agrees that under the CAA and the *American Corn Growers* case, EPA may not preclude a State from conducting its own BART analysis, nor from requiring BART controls at individual sources as determined appropriate through such analysis. Accordingly, as noted above, the proposed regulatory change to the Regional Haze Rule would provide that a CAIR affected State ''need not require affected BART-eligible EGUs to install, operate, and maintain BART'' if such State opts to participate in the CAIR cap and trade program. The optional nature of this language (''need not'' rather than ''may not'') is consistent with the *American Corn Growers* decision, because it does not attempt to mandate that States must consider the CAIR as having met the requirements of BART.

The SNPR preamble summarized the proposal by stating that ''EPA proposes that BART-eligible EGUs in any State affected by CAIR may be exempted from BART controls for SO_2 and NO_X if that State complies with the CAIR requirements through adoption of the CAIR cap and trade programs for SO_2 and NO_X emissions.'' (69 FR 3270). That statement accurately reflected the optional nature of the better-than-BART substitution policy, by providing that sources ''may'' be granted such regulatory flexibility. However, the use of the term ''exempted'' in this context

[155] The SNPR preamble used the term ''exemption'' in describing this policy. As clarified below, and as consistent with the proposed regulatory language, the better-than-BART policy is not actually an exemption but rather an alternative means of compliance.

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was somewhat imprecise. EPA agrees that sources may not be ''exempt'' from BART requirements unless the requirements of 169A(c) are fulfilled. The better-than-BART policy is not an ''exemption'' from BART; it is an alternative regulatory program that would allow Congressionally required emissions reductions from BART-eligible sources to be made in a more cost-effective manner. Moreover, as explained elsewhere in the SNPR and again below, BART-eligible EGUs would not be ''exempt'' from BART because, until the emissions reductions required by the CAIR are fully realized, such sources would remain subject to the possibility of being required to install BART controls if deemed necessary to meet requirements regarding reasonably attributable visibility impairment, as provided by 40 CFR 51.302.

Several commenters asserted that because Congress singled out 26 source categories for the application of BART, there is no basis in law for EPA to ''exempt'' some of these categories. These comments amount to facial challenges of EPA's authority to approve SIPs which contain alternative strategies, rather than source-specific BART requirements, for BART-eligible sources.

The EPA's authority to approve alternative measures to BART, where those measures achieve greater reasonable progress than would BART, was recently upheld by the DC Circuit. (*CEED,* slip. op. at 13). See also Central Arizona *Water Conservation District* v. *EPA,* 990 F.2d 1531, 1543, (1993) (Upholding EPA's interpretation of CAA 169A(b)(2)as providing discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more reasonable progress will thereby be attained).

Similarly, some commenters stated that the CAIR could not substitute for BART because the CAIR and BART are authorized by separate parts of the CAA. They argue that allowing reductions required by a provision of the CAA not linked to visibility improvement to substitute for BART would alter Congress' ''mandate'' that certain source categories make reductions for visibility in excess of what other CAA provisions require of those sources.[156] Commenters also point to Regional Haze Rule section 308(e)(2), as evidence that reductions from other programs such as title IV and the NO_X SIP Call must be achieved in addition to, and not as a substitute for, BART. Commenters also argue that EPA (and States) will need all available tools, including BART, to meet visibility and NAAQS requirements.

Again, under our interpretation of CAA section 169A(b)(2) as upheld in *CEED* and *Central Arizona Water,* Congress did not ''mandate'' that emission reductions from certain source categories be obtained by the installation of BART controls. Instead, the CAA allows for alternative measures to BART—whether for EGUs or non-EGUs—where those measures result in greater reasonable progress, and as explained below, we have determined that greater reasonable progress can be obtained from the EGU sector through the use of the CAIR cap and trade program. However, if a State believes more progress can be made at affected Class I areas by utilizing BART, the State need not make the determination that the CAIR substitutes for BART in that State. Therefore, EPA is not eliminating any tools available to the States.

With respect to Regional Haze Rule section 308(e)(2), EPA does not believe that this section provides any support for the notion that emissions reductions from other programs must necessarily be in addition to, not substitute, for BART. We first note that the decision in CEED necessitates revisions to 308(e)(2), at least in the provisions requiring visibility to be evaluated on a cumulative basis in defining the BART benchmark for comparison to BART alternative programs. It remains to be seen whether 308(e)(2)(iv), which requires that emissions reductions from the BART alternative be ''surplus to reductions resulting from measures adopted to meet requirements as of the baseline date of the SIP,'' will be changed. Even if that section remains unchanged, the CAIR complies with it. The baseline date of Regional Haze SIPs is 2002.[157] Since any emissions reduction requirements to meet the CAIR would necessarily be adopted after 2002, CAIR-required reductions would clearly be surplus to measures adopted as of the baseline year.[158]

Several commenters argued that the question of whether BART is better than the CAIR is properly addressed in the BART rulemaking, not in today's action, and that the better-than-BART determination is otherwise premature. While EPA believes that our current analysis demonstrates that the CAIR is better than BART (based on the criteria in our May 2004 BART proposal), and that the range of uncertainty regarding the presumptive BART controls for EGUs to be finalized in the BART guidelines is not likely to alter that demonstration, we agree that we cannot make a final determination that CAIR is better than BART until the changes to the regional haze regulations required by both *American Corn Growers* and *CEED* are finalized.

Several commenters felt the CAIR should be considered better than BART for a State whether or not that State participates in the CAIR cap and trade program, as long as the State achieves its emission reduction requirement under the CAIR. Conversely, one commenter felt that CAIR reductions should be considered better than BART only when a State does not participate in the cap and trade program, thereby ensuring that the reductions will occur in-State.

Our preliminary demonstration that the CAIR results in more reasonable progress than BART for EGUs is based on a comparison of emissions reductions from EGUs, and attendant air quality effects, under the CAIR as compared to under BART as proposed in May, 2004. If emissions reductions are achieved from other source sectors, a similar analysis would have to be conducted for those sector(s) before it could be determined that the reductions were better than BART for affected source categories. For example, if a State either wants to use EGU emissions reductions under the CAIR to substitute for BART for non-EGUs, or use non-EGU emissions reductions to substitute for BART for EGUs, that could be allowed as an alternative measure to BART provided a similar ''better-than-BART'' determination is made for the sectors involved.

A few commenters believed EPA should not limit the substitution of the CAIR for BART to States that are required to meet CAIR for both SO_2 and NO_X on an annual basis, but rather should also allow it for States which are only required to reduce NO_X during the ozone season. Because the modeling scenarios were based on the pollutants

[156] CAIR is linked to visibility improvements insofar as it attempts to make progress towards attainment of the $PM_{2.5}$ NAAQS, which would, among other things, improve visibility.

[157] See ''2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$ and Regional Haze Programs,'' November 8, 2002, Guidance Memorandum, *http://www.epa.gov/ttn/oarpg/t1/memoranda/2002bye_gm.pdf.*

[158] The purpose of providing a cut-off year for SIP measures to which the alternative must be surplus is to prevent an untenable situation where programs being developed simultaneously must be surplus to each other. Establishing a baseline year allows States to continue to make reductions between that baseline date and the submittal of regional haze SIPs without being ''penalized'' for those reductions by not being allowed to count them as contributing to reasonable progress towards the national visibility goal.

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covered by the CAIR in each affected State, our better-than-BART demonstration is limited to those scenarios. A State subject to the CAIR for NO_X purposes only would have to make a supplementary demonstration that BART has been satisfied for SO_2, as well as for NO_X on an annual basis.

A few commenters believed that the CAIR should satisfy BART for purposes of reasonably attributable visibility impairment as well as BART for purposes of regional haze. Several others commented that it was appropriate or legally necessary to preserve the authority of Federal Land Managers (FLMs) and States to certify impairment and make reasonable attribution determinations, which could subject a source to BART requirements even if the source is a participant in the CAIR cap and trade program. These commenters supported the use of a strategy similar to that employed by the Western Regional Air Partnership, which relies upon a Memorandum Of Understanding (MOU) between the FLMs and the States regarding the criteria by which certifications of impairment may be made, along with the possibility of ''geographic enhancements'' to the cap and trade program to accommodate the imposition of source-specific BART control requirements on a source within the cap and trade program.

As proposed in the SNPR, EPA continues to believe that reasonably attributable visibility impairment determinations under 40 CFR 51.302 must continue to be a viable option in order to insure against any possibility of hot-spots. We believe that a certification of reasonably attributable visibility impairment is fairly unlikely, given that there have been few such certifications since 1980, and given that the reductions from the CAIR and other recent initiatives will make such certifications decreasingly likely. We believe sources can be given sufficient regulatory certainty to enable effective participation in a cap and trade program through the use of MOUs and geographic enhancement provisions.

Some commenters believe that because section 169A(b)(2)(A) requires BART for an eligible source which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area, EPA is without basis in law or regulation to base a better-than-BART determination on an analysis that does not evaluate visibility improvement at each and every Class I area, or one that uses averaging of visibility improvement across different Class I areas.

The criteria we applied in our present analysis—that greater reasonable progress is defined as no degradation at any Class I area, and greater overall average improvement—have not been finalized. However, we disagree with comments that 169A(b)(2)'s requirement of BART for sources reasonably anticipated to contribute to impairment at any Class I area [159] means that an alternative to the BART program must be shown to create improvement at each and every Class I area. Even if a BART alternative is deemed to satisfy BART for regional haze purposes, based on average overall improvement as opposed to improvement at each and every Class I Area, 169A(b)(2)'s trigger for BART based on impairment at any Class I area remains in effect, because a source may become subject to BART based on ''reasonably attributable visibility impairment'' at any area. (The EPA believes it is unlikely that a State or FLM will have need to certify reasonably attributable visibility impairment (RAVI) with respect to any EGU in the CAIR region, but nevertheless believes it is necessary to preserve this safeguard).

We also received a number of comments regarding the broader relationship between the CAIR and regional haze, including whether the CAIR meets reasonable progress requirements, as well as BART, for affected States; whether EPA should allow non-CAIR States to opt in to the CAIR cap and trade program to meet their BART requirements; and whether regional haze provisions should be used as a basis for expanding the CAIR rule to the rest of the States which were not included on the basis of contribution to $PM_{2.5}$ and ozone nonattainment. The EPA's responses to comments on these broader issues, which are not germane to the issue of whether the CAIR may substitute for BART for affected EGUs, are contained in the Response to Comment Document.

c. Today's Action

As discussed above, EPA has the authority to approve SIPs which rely upon a cap and trade program as an alternative to BART. However, at this time, we are deferring a final determination that, in EPA's view, the CAIR makes greater progress than BART for CAIR-affected States until such time as the BART guidelines for EGUs and the criteria for BART-alternative programs are finalized. At that time, contingent upon supporting analysis and our final rules governing the regional haze program, EPA will make a final determination as to whether the CAIR makes greater progress than BART, and can be relied on as an alternative measure in lieu of BART.

2. What Improvements Did EPA Make to the Bart Versus the CAIR Modeling, and What Are the New Results?

a. Supplemental Notice of Proposed Rulemaking

For the better-than-BART analysis in the SNPR, we used the Integrated Planning Model (IPM) to estimate emissions expected after implementation of a source-specific BART approach and after implementation of the CAIR cap and trade program for EGUs. We then used the Regional Modeling System for Aerosols and Deposition (REMSAD) air quality model to project the visibility impact of these IPM emissions predictions for both the CAIR and the nationwide source-specific BART scenarios. Specifically, EPA evaluated the model results for the 20 percent best days (that is, least visibility impaired) and the 20 percent worst days at 44 Class I areas throughout the country. Thirteen of these Class I areas are within States affected by the CAIR proposal, and 31 Class I areas are outside the CAIR region—29 in States to the west of the CAIR region, and 2 in New England States northeast of the CAIR region.

As explained in the SNPR, the ''CAIR'' scenario modeled was imperfect for purposes of this analysis in that it assumed SO_2 reductions on a nationwide basis (rather than in the CAIR region only) and assumed NO_X reductions requirements in a slightly different geographic region than covered by the proposed CAIR. The ideal scenario would have correctly represented the geographic scope of the CAIR SO_2 and NO_X reduction requirements, and included source-specific BART controls in areas outside the CAIR region. (This corrected scenario has been modeled for the NFR, as explained below).

The SNPR REMSAD modeling showed that under the proposed two-pronged test, CAIR controls achieved equal or greater visibility improvement than the application of source-specific BART to EGUs nationwide. The modeling predicted that the CAIR cap and trade program will not result in degradation of visibility, compared to

[159] The question of whether section 169A(b)(2) requires BART based on contribution to impairment at any Class I area is separate from the question of whether this section requires source-specific BART under all circumstances. As noted earlier, we interpret section 169A(b)(2) as requiring BART only as needed to make reasonable progress, thus allowing for alternative measures which make greater reasonable progress.

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existing (1998–2002) visibility conditions, at any of the 44 Class I areas considered. It also indicated that CAIR emissions reductions as modeled produce significantly greater visibility improvements than source-specific BART. Specifically, for the 15 Eastern Class I areas analyzed, the average visibility improvement (on the 20 percent worst days) expected solely as a result of the CAIR was 2.0 deciviews, and the average degree of improvement predicted for source-specific BART was 1.0 deciviews. Similarly, on a national basis, the visibility modeling showed that for all 44 Class I areas evaluated, the average visibility improvement, on the 20 percent worst days, in 2015 was 0.7 deciviews under the CAIR cap and trade program, but only 0.4 deciviews under the source-specific BART approach.

b. Comments and EPA Responses

Several commenters noted that EPA did not model the ''correct'' emissions scenarios to compare the CAIR and BART controls. They suggested that a model run with the CAIR controls in the East and BART controls in the West should be compared to a model run with nationwide BART controls.

The EPA agrees (as we have already noted in the SNPR) that the suggested comparison of model runs is a more appropriate comparison of the CAIR and BART. The SNPR better-than-BART analysis was limited by the availability of the model results at the time. For the NFR, we have modeled nationwide BART for EGUs as proposed in the May 2004 guidelines and a separate scenario consisting of CAIR reductions in the CAIR-affected States plus BART-reductions in the remaining States (excluding Alaska and Hawaii). Additionally, we have improved the BART control assumptions (in both scenarios) by increasing the number of BART-eligible units included. Specifically, in the SNPR analysis, controls were ''required'' (*i.e.*, assumed by the model) for BART-eligible EGUs greater than 250 MW capacity, for both NO_X and SO_2. For today's action, BART controls are assumed for SO_2 for all BART-eligible EGU units greater than 100 MW, and NO_X controls for all BART-eligible EGU units greater than 25 MW.[160] This, along with a review of potentially BART-eligible EGUs, has expanded the universe of units assumed subject to BART in the modeling from 302 to 491.[161]

Several commenters noted that the better-than-BART visibility analysis only covered 44 Class I areas and did not adequately address visibility in all areas of the country.

For the NFR, we have significantly expanded the number of Class I areas covered by the analysis. The NPR and SNPR visibility analysis was limited by the availability of observed data from Inter-agency Monitoring of Protected Visual Environments (IMPROVE) monitors during the meteorological modeling year of 1996. There was complete IMPROVE data at 44 IMPROVE sites which represented 68 Class I areas.[162] All of the regions of the country (as defined by IMPROVE) were represented by at least one site, except the Northern Great Lakes region. For the final rule, the modeling has been updated to use a meteorological year of 2001. Therefore, the IMPROVE data for 2001 was used for the NFR better-than-BART analysis. For 2001, there were 81 IMPROVE sites with complete data,[163] representing 116 Class I areas. The NFR analysis accounts for visibility changes at 80 percent of the active IMPROVE sites in the lower 48 States. More importantly for today's rulemaking, the number of Class I areas in the East has been increased from 15 to 29 and now covers all IMPROVE-defined visibility regions within the CAIR-affected States, including the Northern Great Lakes.[164] We, therefore, believe the expanded geographic scope of Class I areas covered is sufficient for purposes of this analysis.

c. Today's Action

We have compared the two model runs (BART nationwide and BART in the West with the CAIR in the East) using the proposed two-pronged better-than-BART test. The results were analyzed at the 116 Class I areas that have complete IMPROVE data for 2001 or are represented by IMPROVE monitors with complete data. Twenty-nine of the Class I areas are in the East and 87 are in the West. Detailed modeling results for all 116 Class I areas are contained in the Better-than-BART TSD.[165] Results applicable to the better-than-BART proposed two-pronged test are summarized below.

The updated visibility analysis reaffirms that under the proposed two-pronged test, CAIR controls are better than BART for EGUs. The modeling predicts that the CAIR cap and trade program will not result in degradation of visibility on the 20 percent best or 20 percent worst days compared to the 2015 baseline conditions, at any of the 116 Class I areas considered.[166]

With respect to the greater-average-improvement prong, the modeling indicates that CAIR emissions reductions in the East produce significantly greater visibility improvements than source-specific BART. Specifically, for the 29 Eastern Class I areas analyzed, the average visibility improvement, on the 20 percent worst days, expected solely as a result of the CAIR applied in the East and BART applied in the West is 1.6 dv, as compared to the average degree of improvement predicted for nationwide source-specific BART of 0.7 dv. Similarly, on a national basis, the visibility modeling showed that for all 116 Class I areas evaluated, the average visibility improvement, on the 20 percent worst days, in 2015 was 0.5 dv under the CAIR cap and trade program in the East and BART in the West, but only 0.2 deciviews under the nationwide source-specific BART approach.

The modeling showed similar results for the 20 percent best visibility days, although there is less visibility improvement on the best days compared to the worst days. For the 29 Eastern Class I areas analyzed, the average visibility improvement, on the 20 percent best days, expected solely as result of the CAIR applied in the East and BART applied in the West is 0.4 dv, as compared to the average degree of

[160] Because the presumptive controls in the BART guidelines are applicable to coal-fired EGUs, the BART analysis does not assume controls on oil- and gas-fired units. However, NO_X emissions from all (not just BART-eligible) oil and gas steam plants and simple cycle turbines in the CAIR region in the 2010 base case are projected to be about 40,000 tons, or less than 1.5% of the projected total 2010 EGU emissions. By comparison, the modeling of the scenario of the CAIR (with BART in the non-CAIR region) resulted in 640,000 tons of NO_X per year less than the projected emissions under a nationwide BART scenario. Therefore, even if the 40,000 tons of NO_X emissions from oil and gas EGUs were reduced to zero under the BART scenario, the CAIR will still produce significantly greater emission reductions than BART. Also, not all of the oil and gas units associated with those 40,000 tons would be eligible for BART. The IPM does not predict any difference in SO_2 emissions from oil or gas-fired units between the CAIR and BART.

[161] See ''Memo From Perrin Quarles Associates, Inc. Re Follow-Up on Units Potentially Affected by BART, July 19, 2004,'' as Appendix A to the ''Better than BART'' TSD.

[162] Some Class I areas do not have IMPROVE monitors and are represented by nearby IMPROVE sites.

[163] This is the number of IMPROVE sites that are located at or represent Class I areas. There are additional IMPROVE protocol monitoring sites that are not located at Class I areas.

[164] There are 5 Class I areas in the East and 33 Class I areas in the West (outside of the CAIR control region) that do not have complete IMPROVE data for 2001.

[165] ''Demonstration that CAIR Satisfies the 'Better-than-BART' Test As Proposed in the Guidelines for Making BART Determinations,'' March, 2005.

[166] See Better-than-BART TSD for results at each Class I Area.

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improvement predicted for nationwide source-specific BART of 0.2 dv. On a national basis, the visibility modeling showed that for all 116 class I areas evaluated, the average visibility improvement, on the 20 percent best days, in 2015 was 0.1 dv under both the CAIR cap and trade program in the East and BART in the West, and under the nationwide source-specific BART approach. The results are summarized in table IX–1.

TABLE IX–1.—AVERAGE VISIBILITY IMPROVEMENT IN 2015 VS. 2015
Base Case (deciviews)

Class I Areas	CAIR + BART in West		Nationwide BART	
	East [167]	National	East	National
20% Worst Days	1.6	0.5	0.7	0.2
20% Best Days	0.4	0.1	0.2	0.1

The results clearly indicate that the CAIR will achieve greater reasonable progress than BART as proposed, measured by the proposed better-than-BART test. At this time, we can foresee no circumstances under which BART for EGUs could produce greater visibility improvement than the CAIR. However, for the reasons noted in section IX.C.1. above, we are deferring a final determination of whether the CAIR makes greater reasonable progress than BART until the BART guidelines for EGUs and the criteria for BART-alternative programs are finalized.

D. How Will EPA Handle State Petitions Under Section 126 of the CAA?

Section 126 of the CAA authorizes a downwind State to petition EPA for a finding that any new (or modified) or existing major stationary source or group of stationary sources upwind of the State emits or would emit in violation of the prohibition of section 110(a)(2)(D)(i) because their emissions contribute significantly to nonattainment, or interfere with maintenance, of a NAAQS in the State. If EPA makes such a finding, EPA is authorized to directly regulate the affected sources. Section 126 relies on the same statutory provision that underlies the CAIR.

In the January 30, 2004 CAIR proposal, EPA set forth its general view of the approach it expected to take in responding to any section 126 petition that might be submitted which relies on essentially the same record as the CAIR. That approach is the one EPA used in addressing section 126 petitions that were submitted to EPA in 1997 while EPA was developing the NO_X SIP Call to control ozone transport. In the NO_X SIP Call rule, we determined under section 110(a)(2)(D) that the SIP for each affected State (and the District of Columbia) must be revised to eliminate the amount of emissions that contributes significantly to nonattainment in downwind States. The emissions reductions requirement was based on the quantity of emissions that could be eliminated by the application of highly cost-effective controls on specified sources in that State. In May 1999, shortly after promulgation of the NO_X SIP Call, EPA took final action on the section 126 petitions (64 FR 28250; May 25, 1999). The Section 126 action relied on essentially the same record as the NO_X SIP Call. In addition, we established a section 126 remedy based on the same set of highly cost-effective controls. In the May 1999 Section 126 Rule, we determined which petitions had technical merit, but we stopped short of granting the findings for the petitions. Instead, we stated that because we had promulgated the NO_X SIP Call—a transport rule under section 110(a)(2)(D)—as long as an upwind State remained on track to comply with that rule, EPA would defer making the section 126 findings. The findings would be triggered at either of two future dates if specified progress had not been made by those times. The Section 126 Rule included a provision under which the rule would be automatically withdrawn for sources in a State once that State submitted and EPA fully approved a SIP that complied with the NO_X SIP Call. (See 64 FR 28271–28274; May 25, 1999.) The reason for this withdrawal would be the fact that the affected State's SIP revision would fulfill the section 110(a)(2)(D) requirements, so that there would no longer be any basis for the section 126 finding with respect to that State. In this manner, the NO_X SIP Call and the Section 126 Rules would be harmonized.

Under the CAIR proposal, EPA received comments regarding its intended approach for acting on any future section 126 petitions that might be filed. Many commenters expressed support for the approach that EPA had outlined. Other commenters raised issues regarding the timing of emissions reductions under a new section 126 action. Some pointed out that the CAIR compliance date would be later than the 3 years allowed for compliance under section 126. Some were concerned that the proposed CAIR compliance date is later than many attainment dates and States may need section 126 petitions in order to get earlier upwind reductions in order to meet their attainment dates. Some questioned the legal basis for linking the two rules. Several commenters expressed concern that EPA would be restricting the use of or weakening the section 126 provision. A number of commenters urged EPA not to prejudge any petition, but to evaluate each on its own merit. Some thought that any petitions submitted prior to designations or before States had had the opportunity to prepare SIPs would be premature and should be denied. Others suggested that CAIR might not solve all the transport problems and that States would need to retain the section 126 tool to seek further reductions.

After issuing the CAIR proposal, EPA received, on March 19, 2004, a section 126 petition from North Carolina seeking reductions in upwind NO_X and SO_2 for purposes of reducing $PM_{2.5}$ and 8-hour ozone levels in North Carolina. The petition relies in large part on the technical record for the proposed CAIR.

When we propose action on the North Carolina petition, we will set forth our view of the interaction between section 110(a)(2)(D) and section 126. In that proposal, we will take into consideration and respond to the section 126-related comments we received on the CAIR. The EPA will provide a comment period and opportunity for a public hearing on the specifics of that section 126 proposal, including an opportunity to comment on our view of the interaction of the 2 statutory provisions.

[167] Eastern Class I areas are those in the CAIR affected states, except areas in west Texas which are considered western and therefore included in the national average, plus those in New England.

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E. Will Sources Subject to CAIR Also Be Subject to New Source Review?

The EPA did not propose any provisions in the CAIR related to new source review (NSR). Nonetheless, we received some comments on the relationship between CAIR and the NSR provisions that may apply to emissions sources also impacted by the CAIR. Many commenters indicated that if an EGU is part of an EPA-administered regional cap and trade program for NO_X and SO_2, then that EGU should be exempted from NSR for the covered pollutants. The commenters cited Clear Skies legislation as containing provisions affecting NSR for covered sources. In this final rule, EPA is not addressing or revising the provisions of NSR.

It should be noted that pollution control measures implemented by EGUs in compliance with the CAIR may be eligible for an exemption under the NSR pollution control project provision.[168] These provisions provide an exemption from major NSR for controls such as selective catalytic reduction (SCR) for NO_X control and wet scrubbers for SO_2 control, provided that certain conditions identified in the provisions are met.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;

2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

[168] See 40 CFR 51.165(a)(1)(xxv) and 51.165(e), 40 CFR 51.166(b)(31) and 51.166(v), and 40 CFR 51.21(b)(32) and 52.21(z).

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be an economically ''significant regulatory action'' within the meaning of the Executive Order. As a result, today's action was submitted to OMB for review, and EPA has prepared an economic analysis of the rule entitled ''Regulatory Impact Analysis of the Final Clean Air Interstate Rule'' (March 2005).

1. What Economic Analyses Were Conducted for the Rulemaking?

The analyses conducted for this final rule provide several important analyses of impacts on public welfare. These include an analysis of the social benefits, social costs, and net benefits of the regulatory scenario. The economic analyses also address issues involving small business impacts, unfunded mandates (including impacts for Tribal governments), environmental justice, children's health, energy impacts, and requirements of the Paperwork Reduction Act (PRA).

2. What Are the Benefits and Costs of This Rule?

The benefit-cost analysis shows that substantial net economic benefits to society are likely to be achieved due to reductions in emissions resulting from this rule. The results detailed below show that this rule would be highly beneficial to society, with annual net benefits (benefits less costs) of approximately $71.4 or $60.4 billion in 2010 and $98.5 or $83.2 billion in 2015. These alternative net benefits estimates occur due to differing assumptions concerning the social discount rate used to estimate the annual value of the benefits and costs of the rule with the lower estimates relating to a discount rate of 7 percent and the higher estimates a discount rate of 3 percent. All amounts are reflected in 1999 dollars.

The benefits and costs reported for the CAIR represent estimates for the final CAIR program that includes the CAIR promulgated rule and the concurrent proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. The modeling used to provide these estimates also assumes annual SO_2 and NO_X controls for Arkansas that are not a part of the final CAIR program resulting in a slight overstatement of the reported benefits and costs.

a. Control Scenario

Today's rule sets forth requirements for States to eliminate their significant contribution to down-wind nonattainment of the ozone and $PM_{2.5}$ NAAQS. In order to reduce this significant contribution, EPA requires that certain States reduce their emissions of SO_2 and NO_X. The EPA derived the quantities by calculating the amount of SO_2 and NO_X emissions that EPA believes can be controlled from the electric power industry in a highly cost-effective manner. The EPA considered all promulgated CAA requirements and known State actions in the baseline used to develop the estimates of benefits and costs for this rule. For a more complete description of the reduction requirements and how they were calculated, see section IV of today's rulemaking.

Although States may choose to obtain the emissions reductions from other source categories, for purposes of analyzing the impacts of the rule, EPA is assuming the application of the controls that it has identified to be highly cost effective on all EGUs in the transport region.

b. Cost Analysis and Economic Impacts

For the affected region, the projected annual private incremental costs of the CAIR to the power industry are $2.4 billion in 2010 and $3.6 billion in 2015. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions to meet the caps set forth in the rule. Estimates are in 1999 dollars.

In estimating the net benefits of regulation, the appropriate cost measure is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $1.9 billion in 2010 and $2.6 billion in 2015 assuming a 3 percent discount rate. These costs become $2.1 billion in 2010 and $3.1 billion in 2015 assuming a 7 percent discount rate.

Overall, the impacts of the CAIR are modest, particularly in light of the large benefits we expect. Ultimately, we believe the industry will pass along most of the costs of the rule to consumers, so that the costs of the rule will largely fall upon the consumers of electricity. Retail electricity prices are projected to increase roughly 2.0–2.7 percent with the CAIR in the 2010 and 2015 timeframe, and then drop below the 2.0 percent increase level thereafter. The effects of the CAIR on natural gas prices and the power-sector generation mix are relatively small, with a 1.6 percent or less increase in natural gas prices projected from 2010 to 2020.

There will be continued reliance on coal-fired generation, that is projected to remain at roughly 50 percent of total electricity generated. A relatively small amount of coal-fired capacity, about 5.3 GW (1.7 percent of all coal-fired capacity and 0.5 percent of all generating capacity), is projected to be uneconomic to maintain. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region. Units projected to be uneconomic to maintain may be ''mothballed,'' retired, or kept in service to ensure transmission reliability in certain parts of the grid. The EPA's analysis does not address these choices.

As demand grows in the future, additional coal-fired generation is projected to be built under the CAIR. As a result, coal production for electricity generation is projected to increase from 2003 levels by about 15 percent in 2010 and 25 percent by 2020, and we expect a small shift towards greater coal production in Appalachia and the interior coal regions of the country with the CAIR.

For today's rule, EPA analyzed the costs using the Integrated Planning Model (IPM). The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for SO_2 and NO_X throughout the contiguous U.S. for the entire power system. Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/epa-ipm*.

c. Human Health Benefit Analysis

Our analysis of the health and welfare benefits anticipated from this rule are presented in this section. Briefly, the analysis projects major benefits from implementation of the rule in 2010 and 2015. As described below, thousands of deaths and other serious health effects would be prevented. We are able to monetize annual benefits of approximately $73.3 or $62.6 billion in 2010 (based upon a 3 percent or 7 percent discount rate, respectively) and $101 billion or $86.3 billion in 2015 (based upon a discount rate of 3 percent or 7 percent, respectively, 1999 dollars).

Table X–1 presents the primary estimates of reduced incidence of PM- and ozone-related health effects for the years 2010 and 2015 for the regulatory control strategy. In 2015, we estimate that PM-related annual benefits include approximately 17,000 fewer premature fatalities, 8,700 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 10,500 fewer hospitalizations (for respiratory and cardiovascular disease combined) and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of 9.9 million fewer cases) and approximately 1,700,000 fewer work-loss days. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the Eastern U.S.). Based upon modeling for 2015, annual ozone-related health benefits are expected to include 2,800 fewer hospital admissions for respiratory illnesses, 280 fewer emergency room admissions for asthma, 690,000 fewer days with restricted activity levels, and 510,000 fewer days where children are absent from school due to illnesses.

While we did not include in our primary benefits analysis separate estimates of the number of premature deaths that would be avoided due to reductions in ozone levels, recent studies suggest a link between short-term ozone exposures with premature mortality independent of PM exposures. Based upon a recent report by Thurston and Ito, (2001),[169] the EPA Science Advisory Board has recommended that EPA reevaluate the ozone mortality literature for possible inclusion of ozone mortality in the estimate of total benefits. More recently, a comprehensive analysis using data from the National Morbidity, Mortality and Air Pollution Study (NMMAPS) found a significant association between daily ozone levels and daily mortality rates (Bell *et al.* 2004).[170] The analysis estimated a 0.5 percent increase in daily mortality associated with a 10 ppb increase in ozone, based on data from 95 major urban areas. Using a similar magnitude effect estimate, sensitivity analysis estimates suggest that in 2015, the CAIR would result in an additional 500 fewer premature deaths annually due to reductions in daily ambient ozone concentrations. The EPA has sponsored three independent meta-analyses of the ozone mortality epidemiology literature to inform a determination on inclusion of this important health impact in the primary benefits analysis for future regulations.

Table X–2 presents the estimated monetary value of reductions in the incidence of health and welfare effects. Annual PM-related and ozone-related health benefits are estimated to be approximately $72.1 or $61.4 billion in 2010 (3 percent and 7 percent discount rate, respectively) and $99.3 or $84.5 billion in 2015 (3 percent or 7 percent discount rate, respectively). Estimated annual visibility benefits in southeastern Class I areas are approximately $1.14 billion in 2010 and $1.78 billion in 2015. All monetized estimates are stated in 1999$. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the years 2010 and 2015. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year, that accounts for over 90 percent of total benefits.

Table X–3 presents the total monetized net benefits for the years 2010 and 2015. This table also indicates with a ''B'' those additional health and environmental benefits of the rule that we were unable to quantify or monetize. These effects are additive to the estimate of total benefits. A listing of the benefit categories that could not be quantified or monetized in our benefit estimates are provided in Table X–4. We are not able to estimate the magnitude of these unquantified and unmonetized benefits. While EPA believes there is considerable value to the public for the PM-related benefit categories that could not be monetized, we believe these benefits may be small relative to those categories we were able to quantify and monetize. In contrast, EPA believes the monetary value of the ozone-related premature mortality benefits could be substantial. As previously discussed, we estimate that ozone mortality benefits may yield as many as 500 reduced premature mortalities per year and may increase the benefits of CAIR by approximately $3 billion annually.

d. Quantified and Monetized Welfare Benefits

Only a subset of the expected visibility benefits—those for Class I areas in the southeastern U.S. are included in the monetary benefits estimates we project for this rule. We believe the benefits associated with these non-health benefit categories are likely significant. For example, we are able to quantify significant visibility improvements in Class I areas in the Northeast and Midwest, but are unable at present to place a monetary value on these improvements. Similarly, we

[169] Thurston, G.D. and K. Ito. 2001. ''Epidemiological Studies of Acute Ozone Exposures and Mortality''. *J. Expo Anal Environ Epidemiology* 11 (4) :286–294.

[170] Bell, M.L., A. McDermott, S. Zeger, J. Samet, F. Dominichi. 2005. ''Ozone and Mortality in 95 U.S. Urban Communities from 1987 to 2000.'' *Journal of the American Medical Association*. Forthcoming.

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anticipate improvement in visibility in residential areas where people live, work and recreate within the CAIR region for which we are currently unable to monetize benefits. For the Class I areas in the southeastern U.S., we estimate annual benefits of $1.78 billion beginning in 2015 for visibility improvements. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial.

We also quantify nitrogen and sulfur deposition reductions expected to occur as a result of the CAIR and discuss potential benefits from these reductions in section X.A.4 of this preamble. While we are unable to estimate a dollar value associated with these benefits, we are able to quantify acidification improvements in lakes in the Northeast including the Adirondacks and potential benefits of reductions in nitrogen deposition to estuaries such as the Chesapeake Bay.

TABLE X–1.—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [a]

Health Effect	2010 annual incidence reduction	2015 annual incidence reduction
PM–Related endpoints		
Premature Mortality [b, c].		
Adult, age 30 and over	13,000	17,000
Infant, age <1 year	29	36
Chronic bronchitis (adult, age 26 and over)	6,900	8,700
Non-fatal myocardial infarction (adult, age 18 and over)	17,000	22,000
Hospital admissions—respiratory (all ages) [d]	4,300	5,500
Hospital admissions—cardiovascular (adults, age >18) [e]	3,800	5,000
Emergency room visits for asthma (age 18 years and younger)	10,000	13,000
Acute bronchitis, (children, age 8–12)	16,000	19,000
Lower respiratory symptoms (children, age 7–14)	190,000	230,000
Upper respiratory symptoms (asthmatic children, age 9–18)	150,000	180,000
Asthma exacerbation (asthmatic children, age 6–18)	240,000	290,000
Work Loss Days	1,400,000	1,700,000
Minor restricted activity days (adults age 18–65)	8,100,000	9,900,000
Ozone-Related endpoints		
Hospital admissions—respiratory causes (adult, 65 and older) [f]	610	1,700
Hospital admissions—respiratory causes (children, under 2)	380	1,100
Emergency room visit for asthma (all ages)	100	280
Minor restricted activity days (adults, age 18–65)	280,000	690,000
School absence days	180,000	510,000

[a] Incidences are rounded to two significant digits. These estimates represent benefits from the CAIR nationwide. The modeling used to derive these incidence estimates are reflective of those expected for the final CAIR program including the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.
[b] Premature mortality benefits associated with ozone are not analyzed in the primary analysis.
[c] Adult mortality based upon studies by Pope, *et al.* 2002.[171] Infant mortality based upon studies by Woodruff, Grillo, and Schoendorf,1997.[172]
[d] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.
[e] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.
[f] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

TABLE X–2.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS

[Millions of 1999$] [a, b]

Health effect	Pollutant	2010 estimated value of reductions	2015 estimated value of reductions
Premature mortality [c, d]			
Adult >30 years	....	....	....
3 percent discount rate	$PM_{2.5}$	$67,300	$92,800
7 percent discount rate	....	56,600	78,100
Child <1 year	....	168	222
Chronic bronchitis (adults, 26 and over)	$PM_{2.5}$	2,520	3,340
Non-fatal acute myocardial infarctions			
3 percent discount rate	$PM_{2.5}$	1,420	1,850
7 percent discount rate	....	1,370	1,790

[171] Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of American Medical Association* 287:1132–1141.

[172] Woodruff, T.J., J. Grillo, and K.C. Schoendorf. 1997. "The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Infant Mortality and Particulate Air Pollution in the United States." *Environmental Health Perspectives* 105(6):608–612.

[173] U.S. Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. *www.yosemite1.epa.gov/ee/epa/eed/hsf/pages/Guideline.html.* Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circulars.*

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TABLE X–2.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS—Continued

[Millions of 1999$] [a, b]

Health effect	Pollutant	2010 estimated value of reductions	2015 estimated value of reductions
Hospital admissions for respiratory causes	$PM_{2.5}$, O3	45.2	78.9
Hospital admissions for cardiovascular causes	$PM_{2.5}$	80.7	105
Emergency room visits for asthma	$PM_{2.5}$, O3	2.84	3.56
Acute bronchitis (children, age 8–12)	$PM_{2.5}$	5.63	7.06
Lower respiratory symptoms (children, age 7–14)	$PM_{2.5}$	2.98	3.74
Upper respiratory symptoms (asthma, age 9–11)	$PM_{2.5}$	3.80	4.77
Asthma exacerbations	$PM_{2.5}$	10.3	12.7
Work loss days	$PM_{2.5}$,	180	219
Minor restricted activity days (MRADs)	$PM_{2.5}$, O3	422	543
School absence days	O3	12.9	36.4
Worker productivity (outdoor workers, age 18–65)	O3	7.66	19.9
Recreational visibility, 81 Class I areas	$PM_{2.5}$	1,140	1,780
Monetized Total [e]			
Base estimate			
3 percent discount rate	$PM_{2.5}$, O3	73,300 + B	101,000 + B
7 percent discount rate		62,600 + B	86,300 + B

[a] Monetary benefits are rounded to three significant digits. These estimates represent benefits from the CAIR nationwide for NO_X and SO_2 emissions reductions from electricity-generating units sources (with the exception of ozone and visibility benefits). Ozone benefits relate to the eastern United States. Visibility benefits relate to Class I areas in the southeastern United States. The benefit estimates reflected relate to the final CAIR program that includes the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2010 or 2015).

[c] Valuation assumes discounting over the SAB recommended 20 year segmented lag structure described in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005). Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (US EPA, 2000 and OMB, 2003).[173]

[d] Adult mortality based upon studies by Pope *et al.* 2002. Infant mortality based upon studies by Woodruff, Grillo, and Schoendorf, 1997.

[e] B represents the monetary value of health and welfare benefits not monetized. A detailed listing is provided in Table X–4.

3. How Do the Benefits Compare to the Costs of This Final Rule?

The estimated annual private costs to implement the emission reduction requirements of the final rule for the CAIR region are $2.36 in 2010 and $3.57 billion in 2015 (1999$). These costs are the annual incremental electric generation production costs that are expected to occur with the CAIR. The EPA uses these costs as compliance cost estimates in developing cost-effectiveness estimates.

In estimating the net benefits of regulation, the appropriate cost measure is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $1.9 billion in 2010 and $2.6 billion in 2015 assuming a 3 percent discount rate. These costs become $2.1 billion in 2010 and $3.1 billion in 2015, if one assumes a 7 percent discount rate. Thus, the net benefit (social benefits minus social costs) of the program is approximately $71.4 + B billion or $60.4 + B billion (3 percent and 7 percent discount rate, respectively) annually in 2010 and $98.5 + B billion or $83.2 + B billion annually (3 percent and 7 percent discount rate, respectively) in 2015. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

The annualized regional cost of the CAIR, as quantified here, is EPA's best assessment of the cost of implementing the CAIR, assuming that States adopt the model cap and trade program. These costs are generated from rigorous economic modeling of changes in the power sector due to the CAIR. This type of analysis using IPM has undergone peer review and been upheld in Federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the CAIR to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to less than $42 million (see section X. B., Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to the CAIR, such as the costs associated with the retirement of smaller or less efficient EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with title IV that new program entrants face. Costs may be understated since an optimization model was employed that assumes cost minimization, and the regulated community may not react in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared to the quantified costs of the program on the power sector. The annualized cost estimates presented are the best and most accurate based upon available information. In a separate analysis, EPA estimates the indirect costs and impacts of higher electricity prices on the entire economy [see Regulatory Impact Analysis for the Final Clean Air Interstate Rule, Appendix E (March 2005)].

The costs presented here are EPA's best estimate of the direct private costs of the CAIR. For purposes of benefit-cost analysis of this rule, EPA has also estimated the additional costs of the CAIR using alternate discount rates for calculating the social costs, parallel to the range of discount rates used in the estimates of the benefits of the CAIR (3 percent and 7 percent). Using these alternate discount rates, the social costs of the CAIR are $1.9 billion in 2010 and $2.6 billion in 2015 using a discount rate of 3 percent, and $2.1 billion in 2010 and $3.1 billion in 2015 using a discount rate of 7 percent. The costs of the CAIR using the adjusted discount rates are lower than the private costs of the CAIR generated using IPM because the social costs do not include certain transfer payments, primarily taxes, that are considered a redistribution of wealth rather than a social cost.[174]

TABLE X–3.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE CLEAN AIR INTERSTATE RULE [a]

[Billions of 1999 dollars]

Description	2010 (Billions of 1999 dollars)	2015 (Billions of 1999 dollars)
Social Costs: [b]		
3 percent discount rate	$1.91	$2.56
7 percent discount rate	2.14	3.07
Social Benefits: [c,d,e]		
3 percent discount rate	73.3 + B	101 + B
7 percent discount rate	62.6 + B	86.3 + B
Health-related benefits:		
3 percent discount rate	72.1 + B	99.3 + B
7 percent discount rate	61.4 + B	84.5 + B
Visibility benefits	1.14 + B	1.78 + B
Annual Net Benefits (Benefits-Costs): [e,f]		
3 percent discount rate	71.4 + B	98.5 + B
7 percent discount rate	60.4 + B	83.2 + B

[a] All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the years 2010 and 2015. Estimates relate to the complete CAIR program including the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.

[b] Note that costs are the annual total costs of reducing pollutants including NO_X and SO_2 in the CAIR region.

[c] As this table indicates, total benefits are driven primarily by PM-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits in 2015. Benefits in this table are nationwide (with the exception of ozone and visibility) and are associated with NO_X and SO_2 reductions for the EGU source category. Ozone benefits represent benefits in the eastern United States. Visibility benefits represent benefits in Class I areas in the southeastern United States.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in Table X–4.

[e] Valuation assumes discounting over the SAB-recommended 20 year segmented lag structure described in chapter 4 of the Regulatory Impact Analysis for the Clean Air Interstate Rule (March 2005). Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000 and OMB, 2003).[174]

[f] Net benefits are rounded to the nearest $100 million. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Gaps in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While uncertainties in the underlying scientific and economics literatures (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA's inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emissions inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions.

In valuing reductions in premature fatalities associated with PM, we used a value of $5.5 million per statistical life. This represents a central value consistent with a range of values from $1 to $10 million suggested by recent meta-analyses of the wage-risk value of statistical life (VSL) literature.[175]

The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, that are discussed throughout the Regulatory Impact Analysis document [Regulatory

[174] United States Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. *www.yosemitel.epa.gov/ee/epa/eed/hsf/pages/Guideline.html.* Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circulars.*

[175] Mrozek, J.R. and L.O. Taylor, *What determines the value of a life? A Meta Analysis,* Journal of Policy Analysis and Management 21(2), pp. 253–270.

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Impact Analysis for the Final Clean Air Interstate Rule (March 2005)]. As Table X–2 indicates, total benefits are driven primarily by the reduction in premature fatalities each year. Elaborating on the previous uncertainty discussion, some key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) EPA assumes inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Plausible biological mechanisms for this effect have been hypothesized for the endpoints included in the primary analysis and the weight of the available epidemiological evidence supports an assumption of causality.

(2) EPA assumes all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because the proportion of certain components in the PM mixture produced via precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) EPA assumes the C–R function for fine particles is approximately linear within the range of ambient concentrations under consideration. In the PM Criteria Document, EPA recognizes that for individuals and specific health responses there are likely threshold levels, but there remains little evidence of thresholds for PM-related effects in populations.[176] Where potential threshold levels have been suggested, they are at fairly low levels with increasing uncertainty about effects at lower ends of the $PM_{2.5}$ concentration ranges. Thus, EPA estimates include health benefits from reducing the fine particles in areas with varied concentrations of PM, including both regions that are in attainment with fine particle standard and those that do not meet the standard.

The EPA recognizes the difficulties, assumptions, and inherent uncertainties in the overall enterprise. The analyses upon which the CAIR is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

[176] U.S. EPA. (2004). Air Quality Criteria for Particulate Matter. Research Triangle Park, NC: National Center for Environmental Assessment—RTP Office; Report No. EPA/600/P–99/002aD.

There are a number of health and environmental effects that we were unable to quantify or monetize. A complete benefit-cost analysis of the CAIR requires consideration of all benefits and costs expected to result from the rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that were not quantified or monetized in our estimate are provided in Table X–4. These effects are denoted by ''B'' in Table X–3 above, and are additive to the estimates of benefits.

4. What Are the Unquantified and Unmonetized Benefits of the CAIR Emissions Reductions?

Important benefits beyond the human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone are expected to occur from this rule. These other benefits occur both directly from NO_X and SO_2 emissions reductions, and indirectly through reductions in co-pollutants such as mercury. These benefits are listed in Table X–4. Some of the more important examples include: Reductions in NO_X and SO_2 emissions required by the CAIR will reduce acidification and, in the case of NO_X, eutrophication of water bodies. Reduced nitrate contamination of drinking water is another possible benefit of the rule. This final rule will also reduce acid and particulate deposition that cause damages to cultural monuments, as well as, soiling and other materials damage.

To illustrate the important nature of benefit categories we are currently unable to monetize, we discuss two categories of public welfare and environmental impacts related to reductions in emissions required by the CAIR: Reduced acid deposition and reduced eutrophication of water bodies.

a. What Are the Benefits of Reduced Deposition of Sulfur and Nitrogen to Aquatic, Forest, and Coastal Ecosystems?

Atmospheric deposition of sulfur and nitrogen, more commonly known as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, across State borders. Acidic compounds (including small particles such as sulfates and nitrates) cause many negative environmental effects, including acidification of lakes and streams, harm to sensitive forests, and harm to sensitive coastal ecosystems.

i. Acid Deposition and Acidification of Lakes and Streams

The extent of adverse effects of acid deposition on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. The neutralizing ability [key indicator is termed Acid Neutralizing Capacity (ANC)] depends largely on the watershed's physical characteristics: Geology, soils, and size. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly, the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and southeastern streams.

Some of the impacts of today's rulemaking on acidification of water bodies have been quantified. In particular, this rule will result in improvements in the acid buffering capacity for lakes in the Northeast and Adirondack Mountains. Specifically, 12 percent of Adirondack lakes are projected to be chronically acidic in the base case. However, we project that the CAIR rule will eliminate chronic acidification in lakes in the Adirondack Mountains by 2030. In addition, today's rule is expected to decrease the percentage of chronically acidic lakes throughout Northeast from 6 to 1 percent. However, some lakes in the Adirondacks and New England will continue to experience episodic acidification even after implementation of this rule.

In a recent study,[177] Resources for the Future (RFF) estimates total benefits (*i.e.*, the sum of use and nonuse values) of natural resource improvements for the Adirondacks resulting from a program that would reduce acidification in 40 percent of the lakes in the Adirondacks that were of concern for acidification. While this study requires further evaluation, the RFF study suggests that the benefits of acid deposition reductions for the CAIR are likely to be substantial in terms of the total monetized value for ecological endpoints (although likely small in

[177] Banzhaf, Spencer, Dallas Burtraw, David Evans, and Alan Krupnick. ''Valuation of Natural Resource Improvements in the Adirondacks,'' Resources for the Future (RFF), September 2004.

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comparison to the estimated premature mortality benefits estimates).

ii. Acid Deposition and Forest Ecosystem Impacts

Current understanding of the effects of acid deposition on forest ecosystems focuses on the effects of ecological processes affecting plant uptake, retention, and cycling of nutrients within forest ecosystems. Recent studies indicate that acid deposition is at least partially responsible for decreases in base cations (calcium, magnesium, potassium, and others) from soils in the northeastern and southeastern United States. Losses of calcium from forest soils and forested watersheds have now been documented as a sensitive early indicator of soil response to acid deposition for a wide range of forest soils in the United States.

In red spruce stands, a clear link exists between acid deposition, calcium supply, and sensitivity to abiotic stress. Red spruce uptake and retention of calcium is impacted by acid deposition in two main ways: Leaching of important stores of calcium from needles and decreased root uptake of calcium due to calcium depletion from the soil and aluminum mobilization. These changes increase the sensitivity of red spruce to winter injuries under normal winter conditions in the Northeast, result in the loss of needles, slow tree growth, and impair the overall health and productivity of forest ecosystems in many areas of the eastern United States. In addition, recent studies of sugar maple decline in the Northeast demonstrate a link between low base cation availability, high levels of aluminum and manganese in the soil, and increased levels of tree mortality due to native defoliating insects.

Although sulfate is the primary cause of base cation leaching, nitrate is a significant contributor in watersheds that are nearly nitrogen saturated. Base cation depletion is a cause for concern because of the role these ions play in surface water acid neutralization and their importance as essential nutrients for tree growth (calcium, magnesium and potassium).

This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of forest systems in the region.

iii. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources.

Atmospheric deposition of nitrogen is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. There are a few estuaries where atmospheric deposition of nitrogen contributes well over 40 percent of the total nitrogen load; however, in most estuaries for which estimates exist, the contribution from atmospheric deposition ranges from 15–30 percent. The area of the country with the highest air deposition rates (30 percent deposition rates) includes many estuaries along the northeast seaboard from Massachusetts to the Chesapeake Bay and along the central Gulf of Mexico coast.

In 1999, National Oceanic and Atmospheric Administration (NOAA) published the results of a 5-year national assessment of the severity and extent of estuarine eutrophication. An estuary is defined as the inland arm of the sea that meets the mouth of a river. The 138 estuaries characterized in the study represent more than 90 percent of total estuarine water surface area and the total number of U.S. estuaries. The study found that estuaries with moderate to high eutrophication represented 65 percent of the estuarine surface area.

Eutrophication is of particular concern in coastal areas with poor or stratified circulation patterns, such as the Chesapeake Bay, Long Island Sound, and the Gulf of Mexico. In such areas, the ''overproduced'' algae tends to sink to the bottom and decay, using all or most of the available oxygen and thereby reducing or eliminating populations of bottom-feeder fish and shellfish, distorting the normal population balance between different aquatic organisms, and in extreme cases, causing dramatic fish kills. Severe and persistent eutrophication often directly impacts human activities. For example, fishery resource losses can be caused directly by fish kills associated with low dissolved oxygen and toxic blooms. Declines in tourism occur when low dissolved oxygen causes noxious smells and floating mats of algal blooms create unfavorable aesthetic conditions. Risks to human health increase when the toxins from algal blooms accumulate in edible fish and shellfish, and when toxins become airborne, causing respiratory problems due to inhalation. According to the NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms'an indication that eutrophication is well developed in more than half of U.S. estuaries.

This rule is anticipated to reduce nitrogen deposition in the CAIR region. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region. While we are unable to monetize the benefits of such reductions, the Chesapeake Bay Program estimated the reduced mass of delivered nitrogen loads likely to result from the CAIR, based upon the CAIR proposal deposition estimates published in January 2004. Atmospheric deposition of nitrogen accounts for a significant portion of the nitrogen loads to the Chesapeake with 28 percent of the nitrogen loads from the watershed coming from air deposition. Based upon the CAIR proposal, nitrogen deposition rates published in the January 2004 proposal, the Chesapeake Bay Program finds that the CAIR will likely reduce the nitrogen loads to the Bay by 10 million pounds per year by 2010.[178] These substantial nitrogen load reductions more than fulfill the EPA's commitment to reduce atmospheric deposition delivered to the Chesapeake Bay by 8 million pounds.

b. Are There Health or Welfare Disbenefits of the CAIR That Have Not Been Quantified?

In contrast to the additional benefits of the rule discussed above, it is also possible that this rule will result in disbenefits in some areas of the region. Current levels of nitrogen deposition in these areas may provide passive fertilization for forest and terrestrial ecosystems where nutrients are a limiting factor and for some croplands.

The effects of ozone and PM on radiative transfer in the atmosphere can also lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of ultraviolet—b (UVb) radiation to the ground. The EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively

[178] Sweeney, Jeff. ''EPA's Chesapeake Bay Program Air Strategy.'' October 26, 2004.

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small changes in average ozone levels over the course of a year (EPA, 2005a). The EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from ozone-related attenuation of UVb radiation (EPA, 2005b). Sulfate and nitrate particles also scatter UVb, which can decrease exposure of horizontal surfaces to UVb, but increase exposure of vertical surfaces. In this case as well, both the magnitude and direction of the effect of reductions in sulfate and nitrate particles are too uncertain to quantify (EPA, 2004). Ozone is a greenhouse gas, and sulfates and nitrates can reduce the amount of solar radiation reaching the earth, but EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

TABLE X–4.—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE CLEAN AIR INTERSTATE RULE

Pollutant/effects	Effects not included in primary estimates—Changes in:
Ozone Health [a]	Premature mortality [b] Chronic respiratory damage Premature aging of the lungs Non-asthma respiratory emergency room visits Increased exposure to UVb
Ozone Welfare	Yields for –commercial forests –fruits and vegetables –commercial and non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Ecosystem functions Increased exposure to UVb
PM Health [c]	Premature mortality—short term exposures [d] Low birth weight Pulmonary function Chronic respiratory diseases other than chronic bronchitis Non-asthma respiratory emergency room visits Exposure to UVb (+/¥) [e]
PM Welfare	Visibility in many Class I areas Residential and recreational visibility in non-Class I areas Soiling and materials damage Damage to ecosystem functions Exposure to UVb (+/¥) [e]
Nitrogen and Sulfate Deposition Welfare	Commercial forests due to acidic sulfate and nitrate deposition Commercial freshwater fishing due to acidic deposition Recreation in terrestrial ecosystems due to acidic deposition Existence values for currently healthy ecosystems Commercial fishing, agriculture, and forests due to nitrogen deposition Recreation in estuarine ecosystems due to nitrogen deposition Ecosystem functions Passive fertilization
Mercury Health	Incidences of neurological disorders Incidences of learning disabilities Incidences of developmental delays Potential reproductive effects [f] Potential cardiovascular effects,[f] including: –Altered blood pressure regulation [f] –Increased heart rate variability [f] –Myocardial infarction [f]
Mercury Deposition Welfare	Impact on birds and mammals (*e.g.*, reproductive effects) Impacts to commercial, subsistence, and recreational fishing

Notes:

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with ozone health effects including increased airway responsiveness to stimuli, inflamation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Premature mortality associated with ozone is not currently included in the primary analysis. Recent evidence suggests that short-term exposures to ozone may have a significant effect on daily mortality rates, independent of exposure to PM. EPA is currently conducting a series of meta-analyses of the ozone mortality epidemiology literature. EPA will consider including ozone mortality in primary benefits analyses once a peer reviewed methodology is available.

[c] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[d] While some of the effects of short term exposures are likely to be captured in the estimates, there may be premature mortality due to short term exposure to PM not captured in the cohort study upon which the primary analysis is based.

[e] May result in benefits or disbenefits.

[f] These are potential effects as the literature is insufficient.

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B. Paperwork Reduction Act

In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), EPA submitted a proposed Information Collection Request (ICR) (EPA ICR number 2512.01) to the OMB for review and approval on July 19, 2004 (FR 42720–42722). The ICR describes the nature of the information collection and its estimated burden and cost associated with the final rule. In cases where information is already collected by a related program, the ICR takes into account only the additional burden. This situation arises in States that are also subject to requirements of the Consolidated Emissions Reporting Rule (EPA ICR number 0916.10; OMB control number 2060–0088) or for sources that are subject to the Acid Rain Program (EPA ICR number 1633.13; OMB control number 2060–0258) or NO_X SIP Call (EPA ICR number 1857.03; OMB number 2060–0445) requirements.

The EPA solicited comments on specific aspects of the information collection. The purpose of the ICR is to estimate the anticipated monitoring, reporting, and recordkeeping burden estimates and associated costs for States, local governments, and sources that are expected to result from the CAIR.

The recordkeeping and reporting burden to sources resulting from States choosing to participate in a regional cap and trade program are expected to be less than $42 million annually at the time the monitors are implemented. This estimate includes the annualized cost of installing and operating appropriate SO_2 and NO_X emissions monitoring equipment to measure and report the total emissions of these pollutants from affected EGUs serving generators greater than 25 megawatt electrical. The burden to State and local air agencies includes any necessary SIP revisions, performing monitoring certification, and fulfilling audit responsibilities.

In accordance with the Paperwork Reduction Act, on July 19, 2004, an ICR was made available to the public for comment. The 60-day comment period expired September 19, 2004 with no public comments received specific to the ICR.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. § 601 et seq.)(RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. 104–121)(SBREFA), provides that whenever an agency is required to publish a general notice of rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business that is identified by the North American Industry Classification System (NAICS) Code, as defined by the Small Business Administration (SBA); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Table X–5 lists entities potentially impacted by this rule with applicable NAICS code.

X–5.—POTENTIALLY REGULATED CATEGORIES AND ENTITIES

Category	[1] NAICS code	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221112	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	[2] 221112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

According to the SBA size standards for NAICS code 221112 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. *See Michigan* v. *EPA*, 213 F.3d 663, 668–69 (DC Cir., 2000), *cert. den.* 121 S.Ct. 225, 149 L.Ed.2d 135 (2001).

This rule would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary SO_2 and NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose the sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities. Although not required by the RFA, the Agency has conducted a small business analysis.

Overall, about 445 MW of total small entity capacity, or 1.0 percent of total small entity capacity in the CAIR region, is projected to be uneconomic to maintain under the CAIR relative to the base case. In practice, units projected to be uneconomic to maintain may be ''mothballed,'' retired, or kept in service to ensure transmission reliability in certain parts of the grid. Our IPM modeling is unable to distinguish between these potential outcomes.

The EPA modeling identified 264 small entities within the CAIR region based upon the definition of small entity outlined above. From this analysis, EPA excluded 189 small entities that were not projected to have at least one unit with a generating capacity of 25 MW or great operating in the base case. Thus, we found that 75 small entities may potentially be affected by the CAIR. Of these 75 small entities, 28 may experience compliance costs in excess of one percent of revenues in 2010, and 46 may in 2015, based on the Agency's assumptions of how the affected States implement control measures to meet their emissions budgets as set forth in this rulemaking. Potentially affected small entities experiencing compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the CAIR. However, it is the Agency's position that because none of the affected entities currently operate in a competitive market environment, they should be able to pass the costs of complying with the CAIR on to rate-payers. Moreover, the decision to include only units greater than 25 MW in size exempts 185 small entities that would otherwise be potentially affected by the CAIR.

Two other points should be considered when evaluating the impact of the CAIR, specifically, and cap and trade programs more generally, on small entities. First, under the CAIR, the cap and trade program is designed such that States determine how NO_X allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on small entities might choose to allocate NO_X allowances in a manner that is favorable to small entities. Finally, the use of cap and trade in general will limit impacts on small entities relative to a less flexible command-and-control program.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, Local, or Tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

The EPA prepared a written statement for the final rule consistent with the requirements of section 202 of the UMRA. Furthermore, as EPA stated in the rule, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

For several reasons, however, EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. First, it is questionable whether a requirement to submit a SIP revision would constitute a Federal mandate in any case. The obligation for a State to revise its SIP that arises out of section 110(a) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658 (a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

As noted earlier, however, notwithstanding these issues, EPA prepared for the final rule the statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

The EPA conducted an analysis of the economic impacts anticipated from the CAIR for government-owned entities. The modeling conducted using the IPM projects that about 340 MW of municipality-owned capacity (about 0.4 percent of all subdivision, State and municipality capacity in the CAIR region) would be uneconomic to maintain under the CAIR, beyond what is projected in the base case. In practice, however, the units projected to be uneconomic to maintain may be 'mothballed,' retired, or kept in service to ensure transmission reliability in certain parts of the grid. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region.

The EPA modeling identified 265 State or municipally-owned entities, as well as subdivisions, within the CAIR region. The EPA excluded from the analysis government-owned entities that were not projected to have at least one unit with generating capacity of 25 MW or greater in the base case. Thus, we excluded 184 entities from the analysis. We found that 81 government entities will be potentially affected by CAIR. Of the 81 government entities, 20 may experience compliance costs in excess of 1 percent of revenues in 2010, and 39 may in 2015, based on our assumptions of how the affected States implement control measures to meet their emissions budgets as set forth in this rulemaking.

Government entities projected to experience compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the CAIR. However, as noted above, it is EPA's position that because these government entities can pass on their costs of compliance to rate-payers, they will not be significantly impacted. Furthermore, the decision to include only units greater than 25 MW in size exempts 179 government entities that would otherwise be potentially affected by the CAIR.

The above points aside, potentially adverse impacts of the CAIR on State and municipality-owned entities could be limited by the fact that the cap and trade program is designed such that States determine how NO_X allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on State or municipality-owned entities might choose to allocate NO_X allowances in a manner that is favorable to these entities. Finally, the use of cap and trade in general will limit impacts on entities owned by small governments relative to a less flexible command-and-control program.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include

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regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The CAA establishes the relationship between the Federal Government and the States, and this rule does not impact that relationship. Thus, Executive Order 13132 does not apply to this rule. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on this rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This rule does not have ''Tribal implications'' as specified in Executive Order 13175.

This rule addresses transport of pollution that are precurors for ozone and $PM_{2.5}$. The CAA provides for States and Tribes to develop plans to regulate emissions of air pollutants within their jurisdictions. The regulations clarify the statutory obligations of States and Tribes that develop plans to implement this rule. The Tribal Authority Rule (TAR) give Tribes the opportunity to develop and implement CAA programs, but it leaves to the discretion of the Tribe whether to develop these programs and which programs, or appropriate elements of a program, the Tribe will adopt.

This rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, because no Tribe has implemented a federally-enforceable air quality management program under the CAA at this time. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal Government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal Government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. Because this rule does not have Tribal implications, Executive Order 13175 does not apply.

If one assumes a Tribe is implementing a Tribal Implementation Plan, today's rule could have implications for that Tribe, but it would not impose substantial direct costs upon the Tribe, nor preempt Tribal law. As provided above, EPA has estimated that the total annual private costs for the rule for the CAIR region as implemented by State, local, and Tribal governments is approximately $2.4 billion in 2010 and $3.6 billion in 2015 (1999$). There are currently very few emissions sources in Indian country that could be affected by this rule and the percentage of Tribal land that will be impacted is very small. For Tribes that choose to regulate sources in Indian country, the costs would be attributed to inspecting regulated facilities and enforcing adopted regulations.

Although Executive Order 13175 does not apply to this rule, EPA consulted with Tribal officials in developing this rule. The EPA has encouraged Tribal input at an early stage. Also, EPA held periodic meetings with the States and the Tribes during the technical development of this rule. Three meetings were held with the Crow Tribe, where the Tribe expressed concerns about potential impacts of the rule on their coal mine operations. In addition, EPA held three calls with Tribal environmental professionals to address concerns specific to the Tribes. These discussions have given EPA valuable information about Tribal concerns regarding the development of this rule. The EPA has provided briefings for Tribal representatives and the newly formed National Tribal Air Association (NTAA), and other national Tribal forums. Input from Tribal representatives has been taken into consideration in development of this rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045, ''Protection of Children from Environmental Health and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to the Executive Order, because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the strategies in this rule will further improve air quality and will further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking (1) (i) a significant regulatory action under Executive Order 12866 or any successor order, and (ii) likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' This final rule is a significant regulatory action under Executive Order 12866, and this rule may have a significant adverse effect on the supply, distribution, or use of energy.

If States choose to obtain the emissions reductions required by this rule by regulating EGUs, EPA projects that approximately 5.3 GWs of coal-fired generation may be removed from operation by 2010. In practice, however, the units projected to be uneconomic to maintain may be 'mothballed,' retired, or kept in service to ensure transmission reliability in certain parts of the grid. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region. Less conservative assumptions regarding natural gas prices or electricity demand would create a greater incentive to keep these units operational. The EPA projects that the

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average annual electricity price will increase by less than 2.7 percent in the CAIR region and that natural gas prices will increase by less than 1.6 percent. The EPA does not believe that this rule will have any other impacts that exceed the significance criteria.

The EPA believes that a number of features of today's rulemaking serve to reduce its impact on energy supply. First, the optional trading program provides considerable flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. The ability to use banked allowances from the existing title IV SO_2 trading program and the NO_X SIP Call Trading Program also provide additional flexibility. Second, the CAIR caps are set in two phases and provide adequate time for EGUs to install pollution controls. For more details concerning energy impacts, see the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005).

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

This rule would require all sources that participate in the trading program under part 96 to meet the applicable monitoring requirements of part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75 EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under Sec. 75.66 before they are used under part 75.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898, ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,'' requires Federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. According to EPA guidance,[179] agencies are to assess whether minority or low-income populations face risks or a rate of exposure to hazards that are significant and that ''appreciably exceed or is likely to appreciably exceed the risk or rate to the general population or to the appropriate comparison group.'' (EPA, 1998)

In accordance with Executive Order 12898, the Agency has considered whether this rule may have disproportionate negative impacts on minority or low income populations. The Agency expects this rule to lead to reductions in air pollution and exposures generally. For this reason, negative impacts to these sub-populations that appreciably exceed similar impacts to the general population are not expected.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This Section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

Any final action related to CAIR is ''nationally applicable'' within the meaning of section 307(b)(1). As an initial matter, through this rule, EPA interprets section 110 of the CAA, a provision which has nationwide applicability. In addition, CAIR applies to 28 States and the District of Columbia. CAIR is also based on a common core of factual findings and analyses concerning the transport of pollutants between the different States subject to it. Finally, EPA has established uniform approvability criteria that would be applied to all States subject to CAIR. For these reasons, the Administrator also is determining that any final action regarding CAIR is of nationwide scope and effect for purposes of section 307(b)(1). Thus, any petitions for review of final actions regarding CAIR must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Parts 72, 73, 74, 77 and 78

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental

[179] U.S. Environmental Protection Agency, 1998. Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. Office of Federal Activities, Washington, DC, April, 1998.

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relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 96

Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: March 10, 2005.

Stephen L. Johnson,

Acting Administrator.

■ Title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 51—[AMENDED]

■ 1. The authority citation for Part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

§ 51.121 [Amended]

■ 2. Section 51.121 is amended by adding a new paragraph (r) to read as follows:

§ 51.121 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen.

* * * * *

(r)(1) Notwithstanding any provisions of paragraph (p) of this section, subparts A through I of part 96 of this chapter, and any State's SIP to the contrary, the Administrator will not carry out any of the functions set forth for the Administrator in subparts A through I of part 96 of this chapter, or in any emissions trading program in a State's SIP approved under paragraph (p) of this section, with regard to any ozone season that occurs after September 30, 2008.

(2) Except as provided in § 51.123(bb), a State whose SIP is approved as meeting the requirements of this section and that includes an emissions trading program approved under paragraph (p) of this section must revise the SIP to adopt control measures that satisfy the same portion of the State's NO_X emission reduction requirements under this section as the State projected such emissions trading program would satisfy.

■ 3. Revise § 51.122 of subpart G to read as follows:

§ 51.122 Emissions reporting requirements for SIP revisions relating to budgets for NO_X emissions.

(a) For its transport SIP revision under § 51.121, each State must submit to EPA NO_X emissions data as described in this section.

(b) Each revision must provide for periodic reporting by the State of NO_X emissions data to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) Annual reporting. Each revision must provide for annual reporting of NO_X emissions data as follows:

(i) The State must report to EPA emissions data from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.121(g) of this part. This would include all sources for which the State has adopted measures that differ from the measures incorporated into the baseline inventory for the year 2007 that the State developed in accordance with § 51.121(g).

(ii) If sources report NO_X emissions data to EPA annually pursuant to a trading program approved under § 51.121(p) or pursuant to the monitoring and reporting requirements of subpart H of 40 CFR part 75, then the State need not provide annual reporting to EPA for such sources.

(2) Triennial reporting. Each plan must provide for triennial (*i.e.*, every third year) reporting of NO_X emissions data from all sources within the State.

(3) The data availability requirements in § 51.116 must be followed for all data submitted to meet the requirements of paragraphs (b)(1) and (2) of this section.

(c) The data reported in paragraph (b) of this section for stationary point sources must meet the following minimum criteria:

(1) For annual data reporting purposes the data must include the following minimum elements:

(i) Inventory year.
(ii) State Federal Information Placement System code.
(iii) County Federal Information Placement System code.
(iv) Federal ID code (plant).
(v) Federal ID code (point).
(vi) Federal ID code (process).
(vii) Federal ID code (stack).
(viii) Site name.
(ix) Physical address.
(x) SCC.
(xi) Pollutant code.
(xii) Ozone season emissions.
(xiii) Area designation.

(2) In addition, the annual data must include the following minimum elements as applicable to the emissions estimation methodology.

(i) Fuel heat content (annual).
(ii) Fuel heat content (seasonal).
(iii) Source of fuel heat content data.
(iv) Activity throughput (annual).
(v) Activity throughput (seasonal).
(vi) Source of activity/throughput data.
(vii) Spring throughput (%).
(viii) Summer throughput (%).
(ix) Fall throughput (%).
(x) Work weekday emissions.
(xi) Emission factor.
(xii) Source of emission factor.
(xiii) Hour/day in operation.
(xiv) Operations Start time (hour).
(xv) Day/week in operation.
(xvi) Week/year in operation.

(3) The triennial inventories must include the following data elements:

(i) The data required in paragraphs (c)(1) and (c)(2) of this section.
(ii) X coordinate (longitude).
(iii) Y coordinate (latitude).
(iv) Stack height.
(v) Stack diameter.
(vi) Exit gas temperature.
(vii) Exit gas velocity.
(viii) Exit gas flow rate.
(ix) SIC.
(x) Boiler/process throughput design capacity.
(xi) Maximum design rate.
(xii) Maximum capacity.
(xiii) Primary control efficiency.
(xiv) Secondary control efficiency.
(xv) Control device type.

(d) The data reported in paragraph (b) of this section for non-point sources must include the following minimum elements:

(1) For annual inventories it must include:

(i) Inventory year.
(ii) State FIPS code.
(iii) County FIPS code.
(iv) SCC.
(v) Emission factor.
(vi) Source of emission factor.
(vii) Activity/throughput level (annual).
(viii) Activity throughput level (seasonal).
(ix) Source of activity/throughput data.
(x) Spring throughput (%).
(xi) Summer throughput (%).
(xii) Fall throughput (%).
(xiii) Control efficiency (%).
(xiv) Pollutant code.
(xv) Ozone season emissions.
(xvi) Source of emissions data.
(xvii) Hour/day in operation.
(xviii) Day/week in operation.
(xix) Week/year in operations.

(2) The triennial inventories must contain, at a minimum, all the data required in paragraph (d)(1) of this section.

(e) The data reported in paragraph (b) of this section for mobile sources must meet the following minimum criteria:

(1) For the annual and triennial inventory purposes, the following data must be reported:

(i) Inventory year.
(ii) State FIPS code.

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(iii) County FIPS code.
(iv) SCC.
(v) Emission factor.
(vi) Source of emission factor.
(vii) Activity (this must be reported for both highway and nonroad activity. Submit nonroad activity in the form of hours of activity at standard load (either full load or average load) for each engine type, application, and horsepower range. Submit highway activity in the form of vehicle miles traveled (VMT) by vehicle class on each roadway type. Report both highway and nonroad activity for a typical ozone season weekday day, if the State uses EPA's default weekday/weekend activity ratio. If the State uses a different weekday/weekend activity ratio, submit separate activity level information for weekday days and weekend days.)
(viii) Source of activity data.
(ix) Pollutant code.
(x) Summer work weekday emissions.
(xi) Ozone season emissions.
(xii) Source of emissions data.
(2) [Reserved.]

(f) Approval of ozone season calculation by EPA. Each State must submit for EPA approval an example of the calculation procedure used to calculate ozone season emissions along with sufficient information for EPA to verify the calculated value of ozone season emissions.

(g) *Reporting schedules.* (1) Data collection is to begin during the ozone season one year prior to the State's NO_X SIP Call compliance date.

(2) Reports are to be submitted according to paragraph (b) of this section and the schedule in Table 1. After 2008, trienniel reports are to be submitted every third year and annual reports are to be submitted each year that a trienniel report is not required.

TABLE 1.—SCHEDULE FOR SUBMITTING REPORTS

Data collection year	Type of report required
2002	Trienniel.
2003	Annual.
2004	Annual.
2005	Trienniel.
2006	Annual.
2007	Annual.
2008	Trienniel.

(3) States must submit data for a required year no later than 12 months after the end of the calendar year for which the data are collected.

(h) *Data Reporting Procedures.* When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(1) States are required to report emissions data in an electronic format to EPA. Several options are available for data reporting. States can obtain information on the current formats at the following Internet address: *http://www.epa.gov/ttn/chief,* by calling the EPA Info CHIEF help desk at (919) 541–1000 or by sending an e-mail to *info.chief@epa.gov.* Because electronic reporting technology continually changes, States are to contact the Emission Inventory Group (EIG) for the latest specific formats.

(2) For annual reporting (not for triennial reports), a State may have sources submit the data directly to EPA to the extent the sources are subject to a trading program that qualifies for approval under § 51.121(q), and the State has agreed to accept data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

(i) *Definitions.* As used in this section, the following words and terms shall have the meanings set forth below:

(1) *Annual emissions.* Actual emissions for a plant, point, or process, either measured or calculated.

(2) *Ash content.* Inert residual portion of a fuel.

(3) *Area designation.* The designation of the area in which the reporting source is located with regard to the ozone NAAQS. This would include attainment or nonattainment designations. For nonattainment designations, the classification of the nonattainment area must be specified, *i.e.*, transitional, marginal, moderate, serious, severe, or extreme.

(4) *Boiler design capacity.* A measure of the size of a boiler, based on the reported maximum continuous steam flow. Capacity is calculated in units of MMBtu/hr.

(5) *Control device type.* The name of the type of control device (*e.g.*, wet scrubber, flaring, or process change).

(6) *Control efficiency.* The emissions reduction efficiency of a primary control device, which shows the amount of reductions of a particular pollutant from a process's emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(7) *Day/week in operations.* Days per week that the emitting process operates.

(8) *Emission factor.* Ratio relating emissions of a specific pollutant to an activity or material throughput level.

(9) *Exit gas flow rate.* Numeric value of stack gas flow rate.

(10) *Exit gas temperature.* Numeric value of an exit gas stream temperature.

(11) *Exit gas velocity.* Numeric value of an exit gas stream velocity.

(12) *Fall throughput (%).* Portion of throughput for the 3 fall months (September, October, November). This represents the expression of annual activity information on the basis of four seasons, typically spring, summer, fall, and winter. It can be represented either as a percentage of the annual activity (*e.g.*, production in summer is 40 percent of the year's production), or in terms of the units of the activity (*e.g.*, out of 600 units produced, spring = 150 units, summer = 250 units, fall = 150 units, and winter = 50 units).

(13) *Federal ID code (plant).* Unique codes for a plant or facility, containing one or more pollutant-emitting sources.

(14) *Federal ID code (point).* Unique codes for the point of generation of emissions, typically a physical piece of equipment.

(15) *Federal ID code (stack number).* Unique codes for the point where emissions from one or more processes are released into the atmosphere.

(16) *Federal Information Placement System (FIPS).* The system of unique numeric codes developed by the government to identify States, counties, towns, and townships for the entire United States, Puerto Rico, and Guam.

(17) *Heat content.* The thermal heat energy content of a solid, liquid, or gaseous fuel. Fuel heat content is typically expressed in units of Btu/lb of fuel, Btu/gal of fuel, joules/kg of fuel, etc.

(18) *Hr/day in operations.* Hours per day that the emitting process operates.

(19) *Maximum design rate.* Maximum fuel use rate based on the equipment's or process' physical size or operational capabilities.

(20) *Maximum nameplate capacity.* A measure of the size of a generator which is put on the unit's nameplate by the manufacturer. The data element is reported in megawatts (MW) or kilowatts (KW).

(21) *Mobile source.* A motor vehicle, nonroad engine or nonroad vehicle, where:

(i) Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway;

(ii) Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;

(iii) Nonroad vehicle means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

(22) *Ozone season.* The period May 1 through September 30 of a year.

(23) *Physical address.* Street address of facility.

(24) *Point source.* A non-mobile source which emits 100 tons of NO_X or more per year unless the State designates as a point source a non-mobile source emitting at a specified level lower than 100 tons of NO_X per year. A non-mobile source which emits less NO_X per year than the point source threshold is a non-point source.

(25) *Pollutant code.* A unique code for each reported pollutant that has been assigned in the EIIP Data Model. Character names are used for criteria pollutants, while Chemical Abstracts Service (CAS) numbers are used for all other pollutants. Some States may be using storage and retrieval of aerometric data (SAROAD) codes for pollutants, but these should be able to be mapped to the EIIP Data Model pollutant codes.

(26) *Process rate/throughput.* A measurable factor or parameter that is directly or indirectly related to the emissions of an air pollution source. Depending on the type of source category, activity information may refer to the amount of fuel combusted, the amount of a raw material processed, the amount of a product that is manufactured, the amount of a material that is handled or processed, population, employment, number of units, or miles traveled. Activity information is typically the value that is multiplied against an emission factor to generate an emissions estimate.

(27) *SCC.* Source category code. A process-level code that describes the equipment or operation emitting pollutants.

(28) *Secondary control efficiency (%).* The emissions reductions efficiency of a secondary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(29) *SIC.* Standard Industrial Classification code. U.S. Department of Commerce's categorization of businesses by their products or services.

(30) *Site name.* The name of the facility.

(31) *Spring throughput (%).* Portion of throughput or activity for the 3 spring months (March, April, May). See the definition of Fall Throughput.

(32) *Stack diameter.* Stack physical diameter.

(33) *Stack height.* Stack physical height above the surrounding terrain.

(34) *Start date (inventory year).* The calendar year that the emissions estimates were calculated for and are applicable to.

(35) *Start time (hour).* Start time (if available) that was applicable and used for calculations of emissions estimates.

(36) *Summer throughput (%).* Portion of throughput or activity for the 3 summer months (June, July, August). See the definition of Fall Throughput.

(37) *Summer work weekday emissions.* Average day's emissions for a typical day.

(38) *VMT by Roadway Class.* This is an expression of vehicle activity that is used with emission factors. The emission factors are usually expressed in terms of grams per mile of travel. Since VMT does not directly correlate to emissions that occur while the vehicle is not moving, these non-moving emissions are incorporated into EPA's MOBILE model emission factors.

(39) *Week/year in operation.* Weeks per year that the emitting process operates.

(40) *Work Weekday.* Any day of the week except Saturday or Sunday.

(41) *X coordinate (longitude).* An object's east-west geographical coordinate.

(42) *Y coordinate (latitude).* An object's north-south geographical coordinate.

■ 4. Part 51 is amended by adding § 51.123 to Subpart G to read as follows:

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

(a)(1) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (2) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(2)(a) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (3) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8-hour ozone NAAQS.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) In addition to being subject to the requirements in paragraphs (b) and (d) of this section:

(1) Alabama, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, and the District of Columbia shall be subject to the requirements contained in paragraphs (e) through (cc) of this section;

(2) Georgia, Minnesota, and Texas shall be subject to the requirements in paragraphs (e) through (o) and (cc) of this section; and

(3) Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey shall be subject to the requirements contained in paragraphs (q) through (cc) of this section.

(d)(1) The State's SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU NO_X Budget, if applicable, and achieve the State's Annual Non-EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU NO_X Budget and Annual Non-EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a)(1) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures

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under this section on only EGUs, the Annual EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non-EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(1) of this section by imposing control measures on only non-EGUs, then the State's Annual Non-EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(1) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Annual Non-EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU NO_X Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non-EGU NO_X Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only EGUs, the amount of the Annual EGU NO_X Budget, in tons of NO_X per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU NO_X budget for 2009–2014 (tons)	Annual EGU NO_X budget for 2015 and thereafter (tons)
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966

(3) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only non-EGUs, the amount of the Annual Non-EGU NO_X Reduction Requirement, in tons of NO_X per year, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Annual EGU NO_X Budget for the appropriate year, specified in paragraph (e)(2) of this section from the amount of the State's NO_X baseline EGU emissions inventory projected for the appropriate year, specified in Table 5 of ''Regional and State SO_2 and NO_X Budgets'', March 2005 (available at *http://www.epa.gov/cleanairinterstaterule*).

(4)(i) Notwithstanding the State's obligation to comply with paragraph (e)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement control measures to demonstrate compliance using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(4)(ii) of this section.

(ii) The State-by-State amounts of the compliance supplement pool are as follows:

State	Compliance supplement pool
Alabama	10,166
District of Columbia	0
Florida	8,335
Georgia	12,397
Illinois	11,299
Indiana	20,155
Iowa	6,978
Kentucky	14,935
Louisiana	2,251
Maryland	4,670
Michigan	8,347
Minnesota	6,528
Mississippi	3,066
Missouri	9,044
New York	0
North Carolina	0
Ohio	25,037
Pennsylvania	16,009
South Carolina	2,600
Tennessee	8,944
Texas	772
Virginia	5,134
West Virginia	16,929
Wisconsin	4,898

(iii) The SIP revision may provide for the distribution of credits from the compliance supplement pool to sources

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that are required to implement control measures using one or both of the following two mechanisms:

(A) The State may issue credit from compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and that implement NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable at any time during such years. Such a source may be issued one credit from the compliance supplement pool for each ton of such emission reductions in 2007 and 2008.

(1) The State shall complete the issuance process by January 1, 2010.

(2) The emissions reductions for which credits are issued must have been demonstrated by the owners and operators of the source to have occurred during 2007 and 2008 and not to be necessary to comply with any applicable State or federal emissions limitation.

(3) The emissions reductions for which credits are issued must have been quantified by the owners and operators of the source:

(i) For EGUs and for fossil-fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBut/hr, using emissions data determined in accordance with subpart H of part 75 of this chapter; and

(ii) For non-EGUs not described in paragraph (e)(4)(iii)(A)(3)(i) of this section, using emissions data determined in accordance with subpart H of part 75 of this chapter or, if the State demonstrates that compliance with subpart H of part 75 of this chapter is not practicable, determined, to the extent practicable, with the same degree of assurance with which emissions data are determined for sources subject to subpart H of part 75.

(4) If the SIP revision contains approved provisions for an emissions trading program, the owners and operators of sources that receive credit according to the requirements of this paragraph may transfer the credit to other sources or persons according to the provisions in the emissions trading program.

(B) The State may issue credit from the compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and whose owners and operators demonstrate a need for an extension, beyond 2009, of the deadline for the source for implementing such emission controls.

(1) The State shall complete the issuance process by January 1, 2010.

(2) The State shall issue credit to a source only if the owners and operators of the source demonstrate that:

(i) For a source used to generate electricity, implementation of the SIP revision's applicable control measures by 2009 would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible for the owners and operators of the source to obtain a sufficient amount of electricity, to prevent such undue risk, from other electricity generation facilities during the installation of control technology at the source necessary to comply with the SIP revision.

(ii) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by 2009 would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(4)(iii)(B)(2)(i) of this section.

(iii) This demonstration must include a showing that it would not be possible for the source to comply with applicable control measures by obtaining sufficient credits under paragraph (e)(4)(iii)(A) of this section, or by acquiring sufficient credits from other sources or persons, to prevent undue risk.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2009 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(1) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non-EGU NO_X Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the Federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to monitoring requirements in accordance with subpart H of part 75 of this chapter.

(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles

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traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in the years 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are otherwise required by final rules already promulgated, as of May 12, 2005, or adopted or implemented by any federal agency, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2009 or 2015, as appropriate.

(iii) A projection of NO_X mass emissions in 2009 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2009 and 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2009 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2009 and 2015, respectively, may be credited towards the State's Annual Non-EGU NO_X Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

(j) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU NO_X Budget or the Annual Non-EGU NO_X Reduction Requirement, as applicable, under paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

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(l)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AA through II of part 96 of this chapter (CAIR NO_X Annual Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AA through II of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR NO_X opt-in provisions of:

(A) Subpart II of this part and the provisions applicable only to CAIR NO_X opt-in units in subparts AA through HH of this part;

(B) Section 96.188(b) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(b); or

(C) Section 96.188(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(c).

(ii) The State may decline to adopt the allocation provisions set forth in subpart EE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X allowances to individual sources, as follows:

(A) The State's methodology must not allow the State to allocate CAIR NO_X allowances for a year in excess of the amount in the State's Annual EGU NO_X Budget for such year;

(B) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the year after the year of the notification deadline; and

(C) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31 of the year for which the CAIR NO_X allowances are allocated.

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section or § 96.124(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AA through HH of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR NO_X Ozone Season allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(p) [Reserved]

(q) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Ozone Season EGU NO_X Budget, if applicable, and achieve the State's Ozone Season Non-EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Ozone Season EGU NO_X Budget and Ozone Season Non-EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Ozone Season EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for an ozone season, if the State meets the requirements of paragraph (a)(2) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Ozone Season EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (q)(2) of this section.

(ii) The Ozone Season Non-EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (s) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(2) of this section by imposing control measures on only non-EGUs, then the State's Ozone Season Non-EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (q)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(2) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Ozone Season Non-EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (q)(2) of this section for the appropriate period and the amount of the State's Ozone Season EGU NO_X Budget specified in the SIP revision for the appropriate period; and

(B) The Ozone Season EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Ozone Season Non-EGU NO_X Reduction Requirement under paragraph (q)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only EGUs, the amount of the Ozone Season EGU NO_X Budget, in tons of NO_X per ozone season, shall be as follows, for the indicated State for the indicated period:

State	Ozone season EGU NO_X budget for 2009–2014 (tons)	Ozone season EGU NO_X budget for 2015 and thereafter (tons)
Alabama	32,182	26,818

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State	Ozone season EGU NO_X budget for 2009–2014 (tons)	Ozone season EGU NO_X budget for 2015 and thereafter (tons)
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989

(3) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only non-EGUs, the amount of the Ozone Season Non-EGU NO_X Reduction Requirement, in tons of NO_X per ozone season, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Ozone Season EGU NO_X Budget for the appropriate year, specified in paragraph (e)(2) of this section, from the amount of the State's NO_X baseline EGU emissions inventory projected for the ozone season in the appropriate year, specified in Table 7 of "Regional and State SO_2 and NO_X Budgets", March 2005 (available at: *http://www.epa.gov/cleanairinterstaterule*).

(4) Notwithstanding the State's obligation to comply with paragraph (q)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement NO_X emission control measures to demonstrate compliance using NO_X SIP Call allowances allocated under the NO_X Budget Trading Program for any ozone season during 2003 through 2008 that have not been deducted by the Administrator under the NO_X Budget Trading Program, if the SIP revision ensures that such allowances will not be available for such deduction under the NO_X Budget Trading Program.

(r) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (q) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (r)(2)(ii) of this section, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (q) of this section, as applicable, in 2009 and subsequent years.

(s)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(2) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Ozone Season Non-EGU NO_X Reduction Requirement under paragraph (q) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (s)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative ozone season consisting, at the State's election, of the ozone season in 2002, 2003, 2004, or 2005, or an average of 2 or more of those ozone seasons, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to

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monitoring requirements in accordance with subpart H of part 75 of this chapter.

(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in ozone seasons 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline ozone season to the ozone seasons 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline ozone season and ozone season 2009 or ozone season 2015, as appropriate.

(iii) A projection of NO_X mass emissions in ozone season 2009 and ozone season 2015 from the source category assuming the same projected changes as under paragraph (s)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected ozone season 2009 and ozone season 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (s)(2)(iii) of this section for ozone season 2009 and ozone season 2015, respectively, from the lower of the amounts in paragraph (s)(2)(i) or (s)(2)(ii) of this section for ozone season 2009 and ozone season 2015, respectively, may be credited towards the State's Ozone Season Non-EGU NO_X Reduction Requirement in paragraph (q)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(t) Each SIP revision must comply with § 51.116 (regarding data availability).

(u) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (q) of this section as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (u)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

(v) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Ozone Season EGU NO_X Budget or the Ozone Season Non-EGU NO_X Reduction Requirement, as applicable, under paragraph (q) of this section;

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(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (v)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(w)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (v)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(x)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(y) Each SIP revision must comply with § 51.280 (regarding resources).

(z) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(aa)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAAA through IIII of part 96 of this chapter (CAIR Ozone Season NO_X Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (aa)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (q) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (aa)(1) of this section.

(i) The State may expand the applicability provisions in § 96.304 to include all non-EGUs subject to the State's emissions trading program approved under § 51.121(p).

(ii) The State may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) The State may decline to adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(A) The State may provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season, in addition to the amount in the State's Ozone Season EGU NO_X Budget for such ozone season, not exceeding the amount of NO_X SIP Call allowances allocated for the ozone season under the NO_X Budget Trading Program to non-EGUs that the applicability provisions in § 96.304 are expanded to include under paragraph (aa)(2)(i) of this section;

(B) The State's methodology must not allow the State to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of the amount in the State's Ozone Season EGU NO_X Budget for such ozone season plus any additional amount of CAIR Ozone Season NO_X allowances issued under paragraph (aa)(2)(iii)(A) of this section for such ozone season;

(C) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(D) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) A State that adopts an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (o)(1) or (2) of this section or § 51.153(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter, other than as set forth in paragraph (aa)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (aa)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR Ozone Season NO_X allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(bb)(1)(i) The State may revise its SIP to provide that, for each ozone season during which a State implements control measures on EGUs or non-EGUs through an emissions trading program approved under paragraph (aa)(1) or (2) of this section, such EGUs and non-EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121, if the State meets the requirement in paragraph (bb)(1)(ii) of this section.

(ii) For a State under paragraph (bb)(1)(i) of this section, if the State's amount of tons specified in paragraph (q)(2) of this section exceeds the State's amount of NO_X SIP Call allowances allocated for the ozone season in 2009 or in any year thereafter for the same types and sizes of units as those covered by the amount of tons specified in paragraph (q)(2) of this section, then the State must replace the former amount for such ozone season by the latter amount for such ozone season in applying paragraph (q) of this section.

(2) Rhode Island may revise its SIP to provide that, for each ozone season during which Rhode Island implements control measures on EGUs and non-EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this

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chapter as set forth in this paragraph, such EGUs and non-EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121.

(i) Rhode Island must expand the applicability provisions in § 96.304 to include all non-EGUs subject to Rhode Island's emissions trading program approved under § 51.121(p).

(ii) Rhode Island may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) Rhode Island may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that Rhode Island must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 936 tons for 2009 and thereafter;

(iv) Rhode Island may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(A) Rhode Island's methodology must not allow Rhode Island to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 936 tons for 2009 and thereafter;

(B) Rhode Island's methodology must require that, for EGUs commencing operation before January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(C) Rhode Island's methodology must require that, for EGUs commencing operation on or after January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) Notwithstanding a SIP revision by a State authorized under paragraph (bb)(1) of this section or by Rhode Island under paragraph (bb)(2) of this section, if the State's or Rhode Island's SIP that, without such SIP revision, imposes control measures on EGUs or non-EGUs under § 51.121 is determined by the Administrator to meet the requirements of § 51.121, such SIP shall be deemed to continue to meet the requirements of § 51.121.

(cc) The terms used in this section shall have the following meanings:

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or *EGU* means:

(1) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (1) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means:

(1) Starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit;

(2)(i) Except as provided in paragraph (2)(ii) of this definition, starting from the completion of any subsequent physical change in the unit resulting in an increase in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such increased maximum amount

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as specified by the person conducting the physical change; or

(ii) For purposes of applying the definition of the term ''potential electrical output capacity,'' starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Non-EGU means a source of NO_X emissions that is not an EGU.

NO_X Budget Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts A through I of this part and § 51.121, as a means of mitigating interstate transport of ozone and nitrogen oxides.

NO_X SIP Call allowance means a limited authorization issued by the Administrator under the NO_X Budget Trading Program to emit up to one ton of nitrogen oxides during the ozone season of the specified year or any year thereafter, provided that the provision in §51.121(b)(2)(ii)(E) shall not be used in applying this definition.

Ozone season means the period, which begins May 1 and ends September 30 of any year.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel-fired combustion turbine.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

(dd) New Hampshire may revise its SIP to implements control measures on EGUs and non-EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this chapter as set forth in this paragraph.

(1) New Hampshire must expand the applicability provisions in § 96.304 of this chapter to include all non-EGUs subject to New Hampshire's emissions trading program at New Hampshire Code of Administrative Rules, chapter Env-A 3200 (2004).

(2) New Hampshire may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(i) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(ii) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(iii) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(3) New Hampshire may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that New Hampshire must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 3,000 tons for 2009 and thereafter;

(4) New Hampshire may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(i) New Hampshire's methodology must not allow New Hampshire to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 3,000 tons for 2009 and thereafter;

(ii) New Hampshire's methodology must require that, for EGUs commencing operation before January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(iii) New Hampshire's methodology must require that, for EGUs commencing operation on or after January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

■ 5. Part 51 is amended by adding § 51.124 to Subpart G to read as follows:

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

(a) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c) of this

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section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting SO_2 in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) The following States are subject to the requirements of this section: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin, and the District of Columbia.

(d)(1) The SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU SO_2 Budget, if applicable, and achieve the State's Annual Non-EGU SO_2 Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU SO_2 Budget and Annual Non-EGU SO_2 Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU SO_2 Budget for the State is defined as the total amount of SO_2 emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU SO_2 Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non-EGU SO_2 Reduction Requirement, if applicable, is defined as the total amount of SO_2 emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, then the State's Annual Non-EGU SO_2 Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Annual Non-EGU SO_2 Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU SO_2 Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU SO_2 Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non-EGU SO_2 Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only EGUs, the amount of the Annual EGU SO_2 Budget, in tons of SO_2 per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU SO_2 budget for 2010–2014 (tons)	Annual EGU SO_2 budget for 2015 and thereafter (tons)
Alabama	157,582	110,307
District of Columbia	708	495
Florida	253,450	177,415
Georgia	213,057	149,140
Illinois	192,671	134,869
Indiana	254,599	178,219
Iowa	64,095	44,866
Kentucky	188,773	132,141
Louisiana	59,948	41,963
Maryland	70,697	49,488
Michigan	178,605	125,024
Minnesota	49,987	34,991
Mississippi	33,763	23,634
Missouri	137,214	96,050
New York	135,139	94,597
North Carolina	137,342	96,139
Ohio	333,520	233,464
Pennsylvania	275,990	193,193
South Carolina	57,271	40,089
Tennessee	137,216	96,051
Texas	320,946	224,662
Virginia	63,478	44,435
West Virginia	215,881	151,117
Wisconsin	87,264	61,085

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(3) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, the amount of the Annual Non-EGU SO_2 Reduction Requirement, in tons of SO_2 per year, shall be determined, for the State for 2010 and thereafter, by subtracting the amount of the State's Annual EGU SO_2 Budget for the appropriate year, specified in paragraph (e)(2) of this section, from an amount equal to 2 times the State's Annual EGU SO_2 Budget for 2010 through 2014, specified in paragraph (e)(2) of this section.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State, or the State must demonstrate why such emissions cap is not practicable, and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2010 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non-EGU SO_2 Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of SO_2 mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with part 75 of this chapter, if the source category is subject to part 75 monitoring requirements in accordance with part 75 of this chapter.

(B) In the absence of monitoring data in accordance with part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of SO_2 mass emissions from the source category in the years 2010 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2010 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the SO_2 emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2010 or 2015, as appropriate.

(iii) A projection of SO_2 mass emissions in 2010 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2010 and 2015 SO_2 emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2010 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2010 and 2015, respectively,

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may be credited towards the State's Annual Non-EGU SO_2 Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section, as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of SO_2 emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter.

(j) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU SO_2 Budget or the Annual Non-EGU SO_2 Reduction Requirement, as applicable, under paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAA through III of part 96 of this chapter (CAIR SO_2 Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR SO_2 opt-in provisions of subpart III of this part and the provisions applicable only to CAIR SO_2 opt-in units in subparts AAA through HHH of this part.

(ii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(b) of this chapter and the provisions of subpart III of this part applicable only to CAIR SO_2 opt-in units under § 96.288(b).

(iii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR SO_2 opt-in units under § 96.288(c).

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with § 96.123 (o)(1) or (2) or (aa)(1) or (2) of this chapter.

(4) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the SO_2 allowances issued under such emissions trading program shall not, and the SIP revision shall state that such SO_2 allowances shall not, qualify as CAIR SO_2 allowances under any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(p) If a State's SIP revision does not contain an emissions trading program approved under paragraph (o)(1) or (2) of this section but contains control measures on EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section:

(1) The SIP revision shall provide, for each year that the State has such

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obligation, for the permanent retirement of an amount of Acid Rain allowances allocated to sources in the State for that year and not deducted by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section, equal to the difference between—

(A) The total amount of Acid Rain allowances allocated under the Acid Rain Program to the sources in the State for that year; and

(B) If the State's SIP revision contains only control measures on EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in paragraph (e)(2) of this section or, if the State's SIP revision contains control measures on EGUs and non-EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in the SIP revision.

(2) The SIP revision providing for permanent retirement of Acid Rain allowances under paragraph (p)(1) of this section must ensure that such allowances are not available for deduction by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(q) The terms used in this section shall have the following meanings:

Acid Rain allowance means a limited authorization issued by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during the specified year or any year thereafter, except as otherwise provided by the Administrator.

Acid Rain Program means a multi-State sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or *EGU* means:

(1) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (1) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means:

(1) Starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit;

(2)(i) Except as provided in paragraph (2)(ii) of this definition, starting from the completion of any subsequent physical change in the unit resulting in an increase in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such increased maximum amount as specified by the person conducting the physical change; or

(ii) For purposes of applying the definition of the term "potential electrical output capacity," starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other

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deratings), such increased maximum amount as specified by the person conducting the physical change.

Non-EGU means a source of SO_2 emissions that is not an EGU.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel fired combustion turbine.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

■ 6. Part 51 is amended by adding § 51.125 to Subpart G to read as follows:

§ 51.125 Emissions reporting requirements for SIP revisions relating to budgets for SO_2 and NO_X emissions.

(a) For its transport SIP revision under § 51.123 and/or 51.124, each State must submit to EPA SO_2 and/or NO_X emissions data as described in this section.

(1) Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin and the District of Columbia, must report annual (12 months) emissions of SO_2 and NO_X.

(2) Alabama, Arkansas, Connecticut, Deleware, Florida, Illinois, Indinia, Iowa, Kentucky, Lousianna, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin and the District of Columbia must report ozone season (May 1 through September 30) emissions of NO_X.

(b) Each revision must provide for periodic reporting by the State of SO_2 and/or NO_X emissions data as specified in paragraph (a) of this section to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) Every-year reporting cycle. As applicable, each revision must provide for reporting of SO_2 and NO_X emissions data every year as follows:

(i) The States identified in paragraph (a)(1) of this section must report to EPA annual emissions data every year from all SO_2 and NO_X sources within the State for which the State specified control measures in its SIP submission under §§ 51.123 and/or 51.124.

(ii) The States identified in paragraph (a)(2) of this section must report to EPA ozone season and summer daily emissions data every year from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.123.

(iii) If sources report SO_2 and NO_X emissions data to EPA in a given year pursuant to a trading program approved under § 51.123(o) or § 51.124(o) of this part or pursuant to the monitoring and reporting requirements of 40 CFR part 75, then the State need not provide annual reporting of these pollutants to EPA for such sources.

(2) *Three-year reporting cycle.* As applicable, each plan must provide for triennial (*i.e.*, every third year) reporting of SO_2 and NO_X emissions data from all sources within the State.

(i) The States identified in paragraph (a)(1) of this section must report to EPA annual emissions data every third year from all SO_2 and NO_X sources within the State.

(ii) The States identified in paragraph (a)(2) of this section must report to EPA ozone season and ozone daily emissions data every third year from all NO_X sources within the State.

(3) The data availability requirements in § 51.116 must be followed for all data submitted to meet the requirements of paragraphs (b)(1) and (2) of this section.

(c) The data reported in paragraph (b) of this section must meet the requirements of subpart A of this part.

(d) Approval of annual and ozone season calculation by EPA. Each State must submit for EPA approval an example of the calculation procedure used to calculate annual and ozone season emissions along with sufficient information for EPA to verify the calculated value of annual and ozone season emissions.

(e) *Reporting schedules.* (1) Reports are to begin with data for emissions occurring in the year 2008, which is the first year of the 3-year cycle.

(2) After 2008, 3-year cycle reports are to be submitted every third year and every-year cycle reports are to be submitted each year that a triennial report is not required.

(3) States must submit data for a required year no later than 17 months after the end of the calendar year for which the data are collected.

(f) Data reporting procedures are given in subpart A of this part. When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(g) *Definitions.* (1) As used in this section, "ozone season" is defined as follows:

Ozone season.—The five month period from May 1 through September 30.

(2) Other words and terms shall have the meanings set forth in appendix A of subpart A of this part.

PART 72—PERMITS REGULATION

■ 1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 72.2 [Amended]

■ 2. Section 72.2 is amended by:

■ a. Amend the definition of "Acid rain emissions limitation" by replacing, in paragraph (1)(i), the words "an affected unit" with the words "the affected units

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at a source'' and replacing, in paragraph (1)(ii)(C), the words ''compliance subaccount for that unit'' with the words ''compliance account for that source'';

■ b. Amend the definition of ''Advance allowance'' by replacing the word ''unit's'' with the word ''source'';

■ c. Amend the definition of ''Allocate or allocation'' by replacing the words ''unit account'' with the words ''compliance account'';

■ d. Amend the definition of ''Allowance deduction, or deduct'' by replacing the words ''compliance subaccount, or future year subaccount,'' with the words ''compliance account'' and replacing the words ''from an affected unit'' with the words ''from the affected units at an affected source'';

■ e. Amend the definition of ''Allowance transfer deadline'' by replacing the words ''affected unit's compliance subaccount'' with the words ''an affected source's compliance account'' and replacing the words ''the unit's'' with the words ''the source's'';

■ f. Amend the definition of ''Authorized account representative'' by replacing the words ''unit account'' with the words ''compliance account'' and replacing the words ''affected unit'' with the words ''affected source and the affected units at the source'';

■ g. Amend the definition of ''Compliance use date'' by replacing the word ''unit's'' with the word ''source's'';

■ h. Amend the definition of ''Excess emissions'' by, in paragraph (1), replacing the words ''an affected unit'' with the words ''the affected units at an affected source'' and replacing the words ''for the unit'' with the words ''for the source'';

■ i. Amend the definition of ''General account'' by replacing the words ''unit account'' with the words ''compliance account'';

■ j. Amend the definition of ''Offset Plan'' by replacing the word ''unit'' with the word ''source'';

■ k. Amend the definition of ''Recordation, record, or recorded'' by removing the words ''or subaccount'';

■ l. Amend the definition of ''Source'' by replacing the words ''under the Act.'' with the words ''under the Act, provided that one or more combustion or process sources that have, under § 74.4(c) of this chapter, a different designated representative than the designated representative for one or more affected utility units at a source shall be treated as being included in a separate source from the source that includes such utility units for purposes of parts 72 through 78 of this chapter, but shall be treated as being included in the same source as the source that includes such utility units for purposes of section 502(c) of the Act.''

■ m. Amend the definition of ''Spot allowance'' by replacing the word ''unit's'' with the word ''source's''; and

■ n. Revise the definition of ''Cogeneration unit'';

■ o. Add a new definition of ''Compliance account''; and

■ p. Remove the definitions of ''Compliance subaccount'', ''Current year subaccount'', ''Direct Sale Subaccount'', ''Future year subaccount'', and ''Unit account''.

§ 72.2 Definitions.

* * * * *

Cogeneration unit means a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, through sequential use of energy.

* * * * *

Compliance account means an Allowance Tracking System account, established by the Administrator under § 73.31(a) or (b) of this chapter or § 74.40(a) of this chapter for an affected source and for each affected unit at the source.

* * * * *

§ 72.7 [Amended]

■ 3. Section 72.7 is amended in paragraph (c)(1)(ii), in the first sentence, by replacing the word ''unit's Allowance Tracking System account'' with the words ''compliance account of the source that includes the unit'', and by removing the third sentence of paragraph (c)(1)(ii).

§ 72.9 [Amended]

■ 4. Section 72.9 is amended by:

■ a. In paragraph (b)(2), replace the word ''unit'' with the words ''source or unit, as appropriate,'';

■ b. In paragraph (c)(1)(i), replace the words ''unit's compliance subaccount'' with the words ''source's compliance account'' and replace the words ''from the unit'' with the words ''from the affected units at the source'';

■ c. In paragraphs (e)(1) and (e)(2) introductory text, replace the words ''an affected unit'' with the words ''an affected source'';

■ d. In paragraph (g)(6), remove the second sentence; and

■ e. In paragraph (h)(2), replace the word ''unit'' with the word ''source'' wherever it appears.

§ 72.21 [Amended]

■ 5. Section 72.21 is amended by:

■ a. In paragraph (b)(1), remove the word ''affected'' wherever it appears; and

■ b. In paragraph (e)(2), replace the words ''unit account'' with the words ''compliance account''.

§ 72.24 [Amended]

■ 6. Section 72.24 is amended by removing and reserving paragraphs (a)(5), (a)(7), and (a)(10).

§ 72.40 [Amended]

■ 7–8. Section 72.40 is amended, in paragraph (a)(1), replace the words ''unit's compliance subaccount'' with the words ''compliance account of the source where the unit is located''; remove the words '', or in the compliance subaccount of another affected unit at the source to the extent provided in § 73.35(b)(3),''; and replace the words ''from the unit'' with the words ''from the affected units at the source''.

§ 72.72 [Amended]

■ 9. Section 72.72 is amended by:

■ a. In paragraph (a)(1), add the words ''or affected source'' after the words ''affected unit'';

■ b. In paragraph (a)(2), add the words ''or an affected source's'' after the words ''affected unit's''; and

■ c. In paragraph (a)(3), add the words ''or affected source'' after the words ''affected unit'' whenever they appear.

§ 72.73 [Amended]

■ 10. Section 72.73 is amended in paragraph (b)(2) by replacing the words ''the first Acid Rain permit'' with the words ''an Acid Rain permit''.

§ 72.90 [Amended]

■ 11. Section 72.90 is amended by, in paragraph (a), add, after the words ''each calendar year'', the words ''during 1995 through 2005''.

§ 72.95 [Amended]

■ 12. Section 72.95 is amended by:

■ a. In the introductory text, replace the words ''an affected unit's compliance subaccount'' with the words ''an affected source's compliance account''; and

■ b. In paragraph (a), replace the words ''by the unit'' with the words ''by the affected units at the source''.

§ 72.96 [Amended]

■ 13. Section 72.96 is amended in paragraph (b), by replacing the words ''unit''s Allowance Tracking System account'' with the words ''source's compliance account''.

PART 73—SULFUR DIOXIDE ALLOWANCE SYSTEM

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

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§ 73.10 [Amended]

■ 2. Section 73.10 is amended by:

■ a. In paragraph (a), replace the words ''unit account for each'' with the words ''compliance account for each source that includes a'' and remove the words ''in each future year subaccount''; and

■ b. In paragraphs (b)(1) and (b)(2), replace the words ''unit account for each'' with the words ''compliance account for each source that includes a'' and replace the words ''in the future year subaccounts representing calendar years'' with the words ''for the years''.

§ 73.27 [Amended]

■ 3. Section 73.27 is amended in paragraphs (c)(3) and (c)(5) by replacing the words ''unit's Allowance Tracking System account'' with the words ''compliance account of the source that includes the unit''.

§ 73.30 [Amended]

■ 4. Section 73.30 is amended by:

■ a. In paragraph (a), add the word ''compliance'' after the word ''establish''; replace the words ''affected units'' with the words ''affected sources''; and replace the words ''unit's Allowance Tracking System account'' with the words ''source's compliance account''; and

■ b. In paragraph (b), replace the word ''unit'' with the word ''source'' and replace the words ''Allowance Tracking System account'' with the words ''general account''.

§ 73.31 [Amended]

■ 5. Section 73.31 is amended by:

■ a. In paragraph (a), replace the words ''an Allowance Tracking System account'' with the words ''a compliance account'' and replace the words ''each unit'' with the words ''each source that includes a unit'';

■ b. In paragraph (b), replace the words ''an Allowance Tracking System account for the unit.'' with the words ''a compliance account for the source that includes the unit, unless the source already has a compliance account.''; and

■ c. In paragraph (c)(1)(v), replace the words ''Allowance Tracking System account'' with the words ''general account'' and remove the words ''I shall abide by any fiduciary responsibilities assigned pursuant to the binding agreement.''.

§ 73.32 [Removed and Reserved]

■ 6. Section 73.32 is removed and reserved.

§ 73.33 [Amended]

■ 7. Section 73.33 is amended by removing and reserving paragraphs (b) and (c).

§ 73.34 [Amended]

■ 8. Section 73.34 is amended by:

■ a. Revise paragraphs (a) and (b) to read as set forth below;

■ b. In paragraph (c) introductory text, remove the paragraph heading and replace the words ''compliance, current year, and future year'' with the words ''compliance account and general account''.

§ 73.34 Recordation in accounts.

(a) After a compliance account is established under § 73.31(a) or (b), the Administrator will record in the compliance account any allowance allocated to any affected unit at the source for 30 years starting with the later of 1995 or the year in which the compliance account is established and any allowance allocated for 30 years starting with the later of 1995 or the year in which the compliance account is established and transferred to the source with the transfer submitted in accordance with § 73.50. In 1996 and each year thereafter, after Administrator has completed the deductions pursuant to § 73.35(b), the Administrator will record in the compliance account any allowance allocated to any affected unit at the source for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are made) and any allowance allocated for the new 30th year and transferred to the source with the transfer submitted in accordance with § 73.50.

(b) After a general account is established under § 73.31(c), the Administrator will record in the general account any allowance allocated for 30 years starting with the later of 1995 or the year in which the general account is established and transferred to the general account with the transfer submitted in accordance with § 73.50. In 1996 and each year thereafter, after the Administrator has completed the deductions pursuant to § 73.35(b), the Administrator will record in the general account any allowance allocated for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are made) and transferred to the general account with the transfer submitted in accordance with § 73.50.

* * * * *

§ 73.35 [Amended]

■ 9. Section 73.35 is amended by:

■ a. In paragraph (a) introductory text and paragraph (a)(1), replace the words ''unit's'' with the word ''source's'';

■ b. In paragraph (a)(2), replace the word ''Such'' with the word ''The'';

■ c. In paragraph (a)(2)(i), replace the words ''the unit's compliance subaccount'' with the words ''the source's compliance account'';

■ d. In paragraph (a)(2)(ii), replace the words ''the unit's compliance subaccount'' with the words ''the source's compliance account'', replace the words ''compliance subaccount for the unit'' with the words ''source's compliance account'', and replace the word ''or'' with the word ''and'';

■ e. Remove paragraph (a)(2)(iii);

■ f. Add a new paragraph (a)(3);

■ g. In paragraph (b)(1), replace the words ''compliance subaccount'' with the words ''compliance account'', add the words ''available for deduction under paragraph (a) of this section'' after the words ''deduct allowances'', and replace the words ''each affected unit's compliance subaccount'' with the words ''each affected source's compliance account'';

■ h. In paragraph (b)(2), replace the words ''allowances remain in the compliance subaccount'' with the words ''allowances available for deduction under paragraph (a) of this section remain in the compliance account'';

■ i. Remove paragraph (b)(3);

■ j. Revise paragraph (c)(1) to read as set forth below;

■ k. In paragraph (c)(2), replace the words ''for the unit'' with the words ''for the units at the source'', replace the words ''in its compliance subaccount.'' with the words ''in the source's compliance account.'', replace the words ''from the compliance subaccount'' with the words ''from the compliance account'', and replace the words ''unit's compliance subaccount'' with the words ''source's compliance account'';

■ l. In paragraph (d), replace the words ''for each unit'' with the words ''for each source'' and replace the word ''unit's'' with the word ''source's''; and

■ m. Remove paragraph (e).

§ 73.35 Compliance.

(a) * * *

(3) The allowance was not previously deducted by the Administrator in accordance with a State SO_2 mass emissions reduction program under § 51.124(o) of this chapter or otherwise permanently retired in accordance with § 51.124(p) of this chapter.

* * * * *

(c)(1) *Identification of allowances by serial number.* The authorized account representative for a source's compliance account may request that specific allowances, identified by serial number, in the compliance account be deducted for a calendar year in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the

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Administrator by the allowance transfer deadline for the year and include, in a format prescribed by the Administrator, the identification of the source and the appropriate serial numbers.

* * * * *

§ 73.36 [Amended]

■ 10. Section 73.36 is amended by:
■ a. In paragraph (a), replace the words ''Unit accounts.'' with the words ''Compliance accounts.'' and replace with words ''compliance subaccount'' with the words ''compliance account'' whenever they appear; and
■ b. In paragraph (b), replace the words ''current year subaccount'' with the words ''general account'' whenever they appear and replace the words ''at the end of the current calendar year'' with the words ''not transferred pursuant to subpart D to another Allowance Tracking System account''.
■ 11. Section 73.37 is revised to read as follows:

§ 73.37 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 73.38 [Amended]

■ 12. Section 73.38 is amended by:
■ a. In paragraph (a), replace the words ''delete the general account from the Allowance Tracking System.'' with the words ''close the general account.''; and
■ b. In paragraph (b), replace the words ''for a period of a year or more'' with the words ''for a 12-month period or longer''; remove the words ''in its subaccounts''; replace the words ''will notify'' with the words ''may notify''; remove the words ''and eliminated from the Allowance Tracking System''; and remove the last sentence.

§ 73.50 [Amended]

■ 13. Section 73.50 is amended by:
■ a. In paragraph (a), remove the words '', including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year in perpetuity'';
■ b. In paragraph (b)(1)(ii), remove the words '', or correct indication on the allowance transfer where a request involves the transfer of the unit's allowance in perpetuity'';
■ c. In paragraph (b)(2)(ii), remove the words ''Allowance Tracking System'' and ''under 40 CFR part 73, or any other remedies'' and remove the comma after the words ''under State or Federal law''; and
■ d. Remove paragraph (b)(3).

§ 73.51 [Removed and Reserved]

■ 14. Section 73.51 is removed and reserved.

§ 73.52 [Amended]

■ 15. Section 73.52 is amended by:
■ a. In paragraph (a) introductory text, remove the words ''§ 73.50, § 73.51, and'' and add the words ''(or longer as necessary to perform a transfer in perpetuity of allowances allocated to a unit)'' after the words ''five business days'';
■ b. Revise paragraphs (a)(1), (a)(2) and (a)(3);
■ c. Remove paragraph (a)(4);
■ d. Revise paragraph (b); and
■ e. Add a new paragraph (c) to read as follows:

§ 73.52 EPA recordation.

(a) * * *

(1) The transfer is correctly submitted under § 73.50;

(2) The transferor account includes each allowance identified by serial number in the transfer; and

(3) If the allowances identified by serial number specified pursuant to § 73.50(b)(1)(ii) are subject to the limitation on transfer imposed pursuant to § 72.44(h)(1)(i) of this chapter, §74.42 of this chapter, or § 74.47(c) of this chapter, the transfer is in accordance with such limitation.

(b) To the extent an allowance transfer submitted for recordation after the allowance transfer deadline includes allowances allocated for any year before the year in which the allowance transfer deadline occurs, the transfer of such allowance will not be recorded until after completion of the deductions pursuant to § 73.35(b) for year before the year in which the allowance transfer deadline occurs.

(c) Where an allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 73.70 [Amended]

■ 16. Section 73.70 is amended by:
■ a. In paragraph (e), remove the last two sentences.
■ b. In paragraph (f), replace the words ''the subaccount'' by the words ''the Allowance Tracking System account''; and
■ c. In paragraph (i)(1), add the words ''source that includes a'' after the words ''Allowance Tracking System account of each''.

PART 74—SULFUR DIOXIDE OPT-INS

■ 1. The authority citation for part 74 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 74.4 [Amended]

■ 2. Section 74.4 is amended by:
■ a. In paragraph (c)(1), replace the words ''a combustion or process source that is located'' with the words ''one or more combustion or process sources that are located'', replace the words ''such combustion or process source and thereafter, does'' with the words ''such combustion or process sources and thereafter, do'', and replace the words ''designate, for such combustion or process source'' with the words ''designate, for such combustion or process sources''; and
■ b. In paragraph (c)(2), replace the words ''the combustion or process source'' with the words ''the combustion or process sources'' whenever they occur and replace the word ''meets'' with the word ''meet'' in the first sentence.

§ 74.18 [Amended]

■ 3. Section 74.18 is amended in paragraph (d) by removing the last sentence.

§ 74.40 [Amended]

■ 4. Section 74.40 is amended by:
■ a. In paragraph (a), replace the words ''an opt-in account'' with the words ''a compliance account'', replace the words ''an account'' with the words ''a compliance account (unless the source that includes the opt-in source already has a compliance account or the opt-in source has, under § 74.4(c), a different designated representative than the designated representative for the source)'', and remove the last sentence.
■ b. In paragraph (b), replace the words ''allowance account in the Allowance Tracking System'' with the words ''compliance account (unless the source that includes the opt-in source already has a compliance account or the opt-in source has, under § 74.4(c), a different designated representative than the designated representative for the source)''.
■ 5. Section 74.42 is revised to read as follows:

§ 74.42 Limitation on transfers.

(a) With regard to a transfer request submitted for recordation during the period starting January 1 and ending with the allowance transfer deadline in the same year, the Administrator will not record a transfer of an opt-in

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allowance that is allocated to an opt-in source for the year in which the transfer request is submitted or a subsequent year.

(b) With regard to a transfer request during the period starting with the day after an allowance transfer deadline and ending December 31 in the same year, the Administrator will not record a transfer of an opt-in allowance that is allocated to an opt-in source for a year after the year in which the transfer request is submitted.

§ 74.43 [Amended]

■ 6. Section 74.43 is amended by:
■ a. In paragraph (a), remove the words "in lieu of any annual compliance certification report required under subpart I of part 72 of this chapter";
■ b. In paragraph (b)(7), replace the word "At" with the words, "In an annual compliance certification report for a year during 1995 through 2005, at"; and
■ c. In paragraph (b)(8), replace the word "The" with the words, "In an annual compliance certification report for a year during 1995 through 2005, the".

§ 74.44 [Amended]

■ 7. Section 74.44 is amended by:
■ a. In paragraph (c)(1)(ii), remove the words "opt-in source's" and add the words "of the source that includes the opt-in source" after the word "System";
■ b. In paragraphs (c)(2)(iii)(C), (c)(2)(iii)(D), (c)(2)(iii)(E) introductory text, and (c)(2)(iii)(E)(3), replace the words "opt-in source's compliance subaccount" with the words "compliance account of the source that includes the opt-in source" whenever they occur; and
■ c. In paragraph (c)(2)(iii)(F), replace the words "opt-in source's compliance subaccount" with the words "compliance account of the source that includes the opt-in source" and replace the words "source's compliance subaccount" with the words "compliance account of the source that includes the opt-in source".

§ 74.46 [Amended]

■ 8. Section 74.46 is amended by removing and reserving paragraph (b)(2).

§ 74.47 [Amended]

■ 9. Section 74.47 is amended by:
■ a. In paragraph (a)(3)(iv), remove the words "opt-in source's" and add the words "of the source that includes the opt-in source" after the word "System";
■ b. In paragraph (a)(3)(v), replace the word "Each" with the word "The", remove the words "replacement unit's" and "(ATS)", and add the words "of each source that includes a replacement unit" after the word "System";
■ c. In paragraph (a)(6), replace the words "Allowance Tracking System account of each replacement unit" with the words "compliance account of each source that includes a replacement unit";
■ d. In paragraph (c), replace the words "unit account" with the words "compliance account of the source that includes the replacement unit" and replace the words "account in the Allowance Tracking System" with the words "Allowance Tracking System account";
■ e. In paragraph (d)(1)(ii)(C), remove the words "opt-in source's" and "(ATS)" and add the words "of the source that includes the opt-in source" after the word "System";
■ f. In paragraph (d)(1)(ii)(D), replace the words "(ATS) for each" with the words "of each source that includes a";
■ g. In paragraph (d)(2)(i), replace the words "Allowance Tracking System accounts for the opt-in source and for each replacement unit" with the words "compliance account for each source that includes the opt-in source or a replacement unit";
■ h. In paragraph (d)(2)(i)(B), replace the words "Allowance Tracking System account of the opt-in source" with the words "compliance account of the source that includes the opt-in source"; and
■ i. In paragraph (d)(2)(ii), replace the words "Allowance Tracking System accounts for the opt-in source and for each replacement unit" with the words "compliance account for each source that includes the opt-in source or a replacement unit".

§ 74.49 [Amended]

■ 10. Section 74.49 is amended, in paragraph (a) introductory text, by replacing the words "an opt-in source's compliance subaccount" with the words "the compliance account of a source that includes an opt-in source".

§ 74.50 [Amended]

■ 11. Section 74.50 is amended by:
■ a. In paragraph (a)(2) introductory text, add the words "source that includes" after the words "the account of the";
■ b. In paragraph (a)(2)(i), replace the words "opt-in source's compliance subaccount" with the words "the compliance account of the source that includes the opt-in source"; and
■ c. In paragraph (b), replace the words "the opt-in source's unit account" with the words "the compliance account of the source that includes the opt-in source"; and
■ d. In paragraph (d), replace the words "an opt-in source does not hold" with the words "the source that includes the opt-in source does not hold".

PART 77—EXCESS EMISSIONS

■ 1. The authority citation for part 77 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 77.3 [Amended]

■ 2. Section 77.3 is amended by:
■ a. In paragraph (a), replace the words "affected unit" with the words "affected source" and replace the word "unit's Allowance Tracking System account" with the words "source's compliance account";
■ b. In paragraphs (b) and (c), replace the word "unit" with the word "source" wherever it appears; and
■ c. In paragraph (d) introductory text and paragraphs (d)(1) and (d)(2), replace the word "unit" with the word "source" whenever it appears;
■ d. In paragraphs (d)(3) and (d)(4), replace the words "unit's Allowance Tracking System account" with the words "source's compliance account's" whenever they appear; and
■ e. In paragraph (d)(5), replace the words "unit's compliance subaccount" with the words "source's compliance account".

§ 77.4 [Amended]

■ 3. Section 77.4 is amended by:
■ a. In paragraph (b)(1), replace the words "unit's compliance subaccount" with the words "source's compliance account"; and
■ b. In paragraphs (c)(1)(ii)(A), (d)(1), (d)(2), (d)(3), (e)(iv), (g)(2)(ii), (g)(3)(ii), and (g)(3)(iii), replace the word "unit" with the word "source"; and
■ c. In paragraph (k)(2), replace the words "unit's compliance subaccount" with the words "source's compliance account" and replace the word "unit" with the word "source".

§ 77.5 [Amended]

■ 4. Section 77.5 is amended by:
■ a. In paragraph (b), replace the words "compliance subaccount" with the words "compliance account";
■ b. In paragraph (c), replace the words ", from the unit's compliance subaccount" with the words "allocated for the year after the year in which the source has excess emissions, from the source's compliance account", and replace the word "unit's" with the word "source's"; and
■ c. Remove paragraph (d).

§ 77.6 [Amended]

■ 5. Section 77.6 is amended by:
■ a. In paragraph (a)(1), add the words "occur at the affected source" after the

words ''sulfur dioxide'' and replace the words ''owners and operators of the affected unit'' with the words ''owners and operators respectively of the affected source and the affected units at the source or of the affected unit'';

■ b. In paragraph (b)(1)(i)(A), replace the word ''unit'' with the words ''source or unit as appropriate''; and

■ c. In paragraphs (b)(3),(c), and (f), replace the word ''unit'' with the words ''source or unit as appropriate''.

PART 78—APPEAL PROCEDURES

■ 1. The title of part 78 is revised to read as set forth above.

■ 2. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

§ 78.1 [Amended]

■ 3. Section 78.1 is amended by:

■ a. In paragraph (a)(1), replace the words ''parts 72, 73, 74, 75, 76, or 77 of this chapter or part 97 of this chapter'' with the words ''part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through subparts IIII of part 96 of this chapter, or part 97 of this chapter'';

■ b. Revise paragraph (b)(2)(i);

■ c. Add new paragraphs (b)(7), (b)(8), and (b)(9) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(2) * * *

(i) The correction of an error in an Allowance Tracking System account;

* * * * *

(7) Under subparts AA through II of part 96 of this chapter,

(i) The decision on the allocation of CAIR NO_X allowances under § 96.141(b)(2) or (c)(2) of this chapter.

(ii) The decision on the deduction of CAIR NO_X allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X allowances based on the information as adjusted, under § 96.154 of this chapter;

(iii) The correction of an error in a CAIR NO_X Allowance Tracking System account under § 96.156 of this chapter;

(iv) The decision on the transfer of CAIR NO_X allowances under § 96.161 of this chapter;

(v) The finalization of control period emissions data, including retroactive adjustment based on audit;

(vi) The approval or disapproval of a petition under § 96.175 of this chapter.

(8) Under subparts AAA through III of part 96 of this chapter,

(i) The decision on the deduction of CAIR SO_2 allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR SO_2 allowances based on the information as adjusted, under § 96.254 of this chapter;

(ii) The correction of an error in a CAIR SO_2 Allowance Tracking System account under § 97.256 of this chapter;

(iii) The decision on the transfer of CAIR SO_2 allowances under § 96.261 of this chapter;

(iv) The finalization of control period emissions data, including retroactive adjustment based on audit;

(v) The approval or disapproval of a petition under § 96.275 of this chapter.

(9) Under subparts AAAA through IIII of part 96 of this chapter,

(i) The decision on the allocation of CAIR NO_X Ozone Season allowances under § 96.341(b)(2) or (c)(2)of this chapter.

(ii) The decision on the deduction of CAIR NO_X Ozone Season allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X Ozone Season allowances based on the information as adjusted, under § 96.354 of this chapter;

(iii) The correction of an error in a CAIR NO_X Ozone Season Allowance Tracking System account under § 96.356 of this chapter;

(iv) The decision on the transfer of CAIR NO_X Ozone Season allowances under § 96.361;

(v) The finalization of control period emissions data, including retroactive adjustment based on audit;

(vi) The approval or disapproval of a petition under § 96.375 of this chapter.

* * * * *

§ 78.3 [Amended]

■ 4. Section 78.3 is amended by:

■ a. In paragraph (b)(3)(i), add the words ''or the CAIR designated representative or CAIR authorized account representative under paragraph (a)(4), (5), or (6) of this section (unless the CAIR designated representative or CAIR authorized account representative is the petitioner)'' after the words ''(unless the NO_X authorized account representative is the petitioner)'';

■ b. In paragraph (c)(7), replace the words ''or part 97 of this chapter, as appropriate'' with the words '', subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, subparts AAAA through IIII of part 96 of this chapter, or part 97 of this chapter, as appropriate'';

■ c. In paragraph (d)(3), add the words ''or on an account certificate of representation submitted by a CAIR designated representative or an application for a general account submitted by a CAIR authorized account representative under subparts AA through II, subparts AAA through III, or subparts AAAA through IIII of part 96 of this chapter'' after the words ''under the NO_X Budget Trading Program'';

■ d. Add new paragraphs (a)(4), (a)(5), (a)(6), (d)(5), (d)(6), and (d)(7) to read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(4) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AA through II of part 96 of this chapter and that is appealable under § 78.1(a):

(i) The CAIR designated representative for a unit or source, or the CAIR authorized account representative for any CAIR NO_X Allowance Tracking System account, covered by the decision; or

(ii) Any interested person.

(5) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAA through III of part 96 of this chapter and that is appealable under § 78.1(a):

(i) The CAIR designated representative for a unit or source, or the CAIR authorized account representative for any CAIR SO_2 Allowance Tracking System account, covered by the decision; or

(ii) Any interested person.

(6) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAAA through IIII of part 96 of this chapter and that is appealable under § 78.1(a):

(i) The CAIR designated representative for a unit or source, or the CAIR authorized account representative for any CAIR Ozone Season NO_X Allowance Tracking System account, covered by the decision; or

(ii) Any interested person.

* * * * *

(d) * * *

(5) Any provision or requirement of subparts AA through II of part 96 of this chapter, including the standard requirements under § 96.106 of this chapter and any emission monitoring or reporting requirements.

(6) Any provision or requirement of subparts AAA through III of part 96 of this chapter, including the standard requirements under § 96.206 of this

chapter and any emission monitoring or reporting requirements.

(7) Any provision or requirement of subparts AAAA through IIII of part 96 of this chapter, including the standard requirements under § 96.306 of this chapter and any emission monitoring or reporting requirements.

§ 78.4 [Amended]

■ 5. Section 78.4 is amended by adding two new sentences after the fifth sentence in paragraph (a) to read as follows:

§ 78.4 Filings.

(a) * * * Any filings on behalf of owners and operators of a CAIR NO_X, SO_2, or NO_X Ozone Season unit or source shall be signed by the CAIR designated representative. Any filings on behalf of persons with an interest in CAIR NO_X allowances, CAIR SO_2 allowances, or CAIR NO_X Ozone Season allowances in a general account shall be signed by the CAIR authorized account representative. * * *

* * * * *

§ 78.5 [Amended]

■ 6. Section 78.5 is amended, in paragraph (a), by removing the words ", or a claim or error notification was submitted," the words "or in the claim of error notification", and the words "or the period for submitting a claim of error notification".

§ 78.12 [Amended]

■ 7. Section 78.12 is amended by:

■ a. In paragraph (a) introductory text, remove the words ", or to submit a claim of error notification"; and

■ b. In paragraph (a)(2), replace the words "NO_X Budget permit" with the words ", NO_X Budget permit, CAIR permit,".

§ 78.13 [Amended]

■ 8. Section 78.13 is amended by, in paragraph (b), removing the word "also".

PART 96—[AMENDED]

■ 1. Authority citation for Part 96 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7601, and 7651, *et seq.*

■ 2. Part 96 is amended by adding subparts AA through II, to read as follows:

Subpart AA—CAIR NO_X Annual Trading Program General Provisions

Sec.

Subpart BB—CAIR Designated Representative for CAIR NO_X Sources

Subpart CC—Permits

Subpart DD—[Reserved]

Subpart EE—CAIR NO_X Allowance Allocations

Subpart FF—CAIR NO_X Allowance Tracking System

Subpart GG—CAIR NO_X Allowance Transfers

Subpart HH—Monitoring and Reporting

Subpart II—CAIR NO_X Opt-in Units

Subpart AA—CAIR NO_X Annual Trading Program General Provisions

§ 96.101 Purpose.

This subpart and subparts BB through II establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BB through II as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.123(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.123(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO_X Annual Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.102 Definitions.

The terms used in this subpart and subparts BB through II shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO_X Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

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Allocate or allocation means, with regard to CAIR NO_X allowances issued under subpart EE, the determination by the permitting authority or the Administrator of the amount of such CAIR NO_X allowances to be initially credited to a CAIR NO_X unit or a new unit set-aside and, with regard to CAIR NO_X allowances issued under § 96.188, the determination by the permitting authority of the amount of such CAIR NO_X allowances to be initially credited to a CAIR NO_X unit.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR NO_X allowance transfer must be submitted for recordation in a CAIR NO_X source's compliance account in order to be used to meet the source's CAIR NO_X emissions limitation for such control period in accordance with § 96.154.

Alternate CAIR designated representative means, for a CAIR NO_X source and each CAIR NO_X unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BB and II of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO_X Annual Trading Program. If the CAIR NO_X source is also a CAIR SO_2 source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BB and II of this part, to transfer and otherwise dispose of CAIR NO_X allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO_X source and each CAIR NO_X unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO_X Annual Trading Program. If the CAIR NO_X source is also a CAIR SO_2 source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X allowance means a limited authorization issued by the permitting authority under subpart EE of this part or § 96.188 to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO_X Program. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan that are approved under § 51.123(o)(1) or (2) of this chapter shall not be a CAIR NO_X allowance.

CAIR NO_X allowance deduction or *deduct CAIR NO_X allowances* means the permanent withdrawal of CAIR NO_X allowances by the Administrator from a compliance account in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO_X units at a CAIR NO_X source for a control period, determined in accordance with subpart HH of this part, or to account for excess emissions.

CAIR NO_X Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO_X allowances under the CAIR NO_X Annual Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NO_X Allowance Tracking System account means an account in the CAIR NO_X Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO_X allowances.

CAIR NO_X allowances held or *hold CAIR NO_X allowances* means the CAIR NO_X allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FF, GG, and II of this part, in a CAIR NO_X Allowance Tracking System account.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X emissions limitation means, for a CAIR NO_X source, the tonnage equivalent of the CAIR NO_X allowances available for deduction for the source under § 96.154(a) and (b) for a control period.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and, except for purposes of § 96.105 and

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subpart EE of this part, a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CC of this part, including any permit revisions, specifying the CAIR NO_X Annual Trading Program requirements applicable to a CAIR NO_X source, to each CAIR NO_X unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:

(1) Except for purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(2) For purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.105.

(i) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.105, for a unit that is not a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NO_X unit under § 96.104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.184(h) or § 96.187(b)(3), for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.184(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.105.

(i) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the

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unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.105, for a unit that is not a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X unit under § 96.104.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.184(h) or § 96.187(b)(3), for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.184(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NO_X Allowance Tracking System account, established by the Administrator for a CAIR NO_X source under subpart FF or II of this part, in which any CAIR NO_X allowance allocations for the CAIR NO_X units at the source are initially recorded and in which are held any CAIR NO_X allowances available for use for a control period in order to meet the source's CAIR NO_X emissions limitation in accordance with § 96.154.

Continuous emission monitoring system or *CEMS* means the equipment required under subpart HH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2; and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO_X units at a CAIR NO_X source during a control period that exceeds the CAIR NO_X emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO_X Allowance Tracking System account, established under subpart FF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion

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device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO_X emissions limitation means, with regard to a unit, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year.

Operator means any person who operates, controls, or supervises a CAIR NO_X unit or a CAIR NO_X source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO_X source or a CAIR NO_X unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO_X unit at the source or the CAIR NO_X unit;

(ii) Any holder of a leasehold interest in a CAIR NO_X unit at the source or the CAIR NO_X unit; or

(iii) Any purchaser of power from a CAIR NO_X unit at the source or the CAIR NO_X unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO_X unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO_X allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR NO_X allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO_X Annual Trading Program in accordance with subpart CC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, *record*, or *recorded* means, with regard to CAIR NO_X allowances, the movement of CAIR NO_X allowances by the Administrator into or between CAIR NO_X Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR NO_X allowance, the unique identification number assigned to each CAIR NO_X allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from

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electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the States or the District of Columbia that adopts the CAIR NO_X Annual Trading Program pursuant to § 51.123(o)(1) or (2) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NO_X emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.103 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
hr—hour.
kW—kilowatt electrical. kWh—kilowatt hour. mmBtu—million Btu.
MWe—megawatt electrical. MWh—megawatt hour.
O_2—oxygen. ppm—parts per million. lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr—year.

§ 96.104 Applicability.

The following units in a State shall be CAIR NO_X units, and any source that includes one or more such units shall be a CAIR NO_X source, subject to the requirements of this subpart and subparts BB through HH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.105 Retired unit exemption.

(a)(1) Any CAIR NO_X unit that is permanently retired and is not a CAIR NO_X opt-in unit under subpart II of this part shall be exempt from the CAIR NO_X Annual Trading Program, except for the provisions of this section, § 96.102, § 96.103, § 96.104, § 96.106(c)(4) through (8), § 96.107, and subparts EE through GG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO_X unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

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(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO_X allowances under subpart EE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.106 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR NO_X source required to have a title V operating permit and each CAIR NO_X unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.122 in accordance with the deadlines specified in § 96.121(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X source required to have a title V operating permit and each CAIR NO_X unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II of this part, the owners and operators of a CAIR NO_X source that is not otherwise required to have a title V operating permit and each CAIR NO_X unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC of this part for such CAIR NO_X source and such CAIR NO_X unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source and each CAIR NO_X unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NO_X source with the CAIR NO_X emissions limitation under paragraph (c) of this section.

(c) *Nitrogen oxides emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under § 96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with subpart HH of this part.

(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under § 96.170(b)(1),(2), or (5).

(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with subpart EE of this part.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X unit.

(d) *Excess emissions requirements.* (1) If a CAIR NO_X source emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation, then:

(i) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under § 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved.]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of

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the CAIR NO_X source and each CAIR NO_X unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.113 for the CAIR designated representative for the source and each CAIR NO_X unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.113 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program.

(2) The CAIR designated representative of a CAIR NO_X source and each CAIR NO_X unit at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, including those under subpart HH of this part.

(f) *Liability.* (1) Each CAIR NO_X source and each CAIR NO_X unit shall meet the requirements of the CAIR NO_X Annual Trading Program.

(2) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X source or the CAIR designated representative of a CAIR NO_X source shall also apply to the owners and operators of such source and of the CAIR NO_X units at the source.

(3) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X unit or the CAIR designated representative of a CAIR NO_X unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR NO_X Annual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source or CAIR NO_X unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO_X Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.108 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO_X Annual Trading Program are set forth in part 78 of this chapter.

Subpart BB—CAIR Designated Representative for CAIR NO_X Sources

§ 96.110 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.111, each CAIR NO_X source, including all CAIR NO_X units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO_X Annual Trading Program concerning the source or any CAIR NO_X unit at the source.

(b) The CAIR designated representative of the CAIR NO_X source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO_X units at the source and shall act in accordance with the certification statement in § 96.113(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.113, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO_X source represented and each CAIR NO_X unit at the source in all matters pertaining to the CAIR NO_X Annual Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO_X Allowance Tracking System account will be established for a CAIR NO_X unit at a source, until the Administrator has received a complete certificate of representation under § 96.113 for a CAIR designated representative of the source and the CAIR NO_X units at the source.

(e)(1) Each submission under the CAIR NO_X Annual Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO_X source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR NO_X source or a CAIR NO_X unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.111 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.113 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

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(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.113, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.102, 96.110(a) and (d), 96.112, 96.113, 96.151 and 96.182, whenever the term ''CAIR designated representative'' is used in subparts AA through II of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.112 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NO_X source and the CAIR NO_X units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NO_X source and the CAIR NO_X units at the source.

(c) Changes in owners and operators. (1) In the event a new owner or operator of a CAIR NO_X source or a CAIR NO_X unit is not included in the list of owners and operators in the certificate of representation under § 96.113, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NO_X source or a CAIR NO_X unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.113 amending the list of owners and operators to include the change.

§ 96.113 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NO_X source, and each CAIR NO_X unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO_X source and of each CAIR NO_X unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO_X unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each CAIR NO_X unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR NO_X unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_X unit, or where a customer purchases power from a CAIR NO_X unit under a life-of- the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO_X unit at the source; and CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X allowances by contract, CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.114 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.113 is received by the Administrator.

(b) Except as provided in § 96.112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NO_X Annual Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate

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any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR NO_X allowance transfers.

Subpart CC—Permits

§ 96.120 General CAIR Annual Trading Program permit requirements.

(a) For each CAIR NO_X source required to have a title V operating permit or required, under subpart II of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart II of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO_X source and the CAIR NO_X units at the source covered by the CAIR permit, all applicable CAIR NO_X Annual Trading Program, CAIR NO_X Ozone Season Trading Program, and CAIR SO_2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.121 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR NO_X source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.122 for the source covering each CAIR NO_X unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO_X unit commences operation.

(b) *Duty to Reapply.* For a CAIR NO_X source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 96.122 for the source covering each CAIR NO_X unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.122 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NO_X source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR NO_X source;

(b) Identification of each CAIR NO_X unit at the CAIR NO_X source; and

(c) The standard requirements under § 96.106.

§ 96.123 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.122.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.102 and, upon recordation by the Administrator under subpart FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from the compliance account of the CAIR NO_X source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO_X source's title V operating permit or other federally enforceable permit as applicable.

§ 96.124 CAIR permit revisions.

Except as provided in § 96.123(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DD—[Reserved]

Subpart EE—CAIR NO_X Allowance Allocations

§ 96.140 State trading budgets.

The State trading budgets for annual allocations of CAIR NO_X allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845

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State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966

§ 96.141 Timing requirements for CAIR NO_X allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X allowance allocations in accordance with paragraph (b)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period.

(c)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period and except that any CAIR NO_X unit that would otherwise be allocated CAIR NO_X allowances under § 96.142(a) and (b), as well as under § 96.142(a), (c), and (d), for the applicable control period will be assumed to be allocated no CAIR NO_X allowances under § 96.142(a), (c), and (d) for the applicable control period.

§ 96.142 CAIR NO_X allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO_X allowance allocations under paragraph (b) of this section for each CAIR NO_X unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit's control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit's control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input, and a unit's status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NO_X emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,414 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO_X units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO_X allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO_X emissions in the State trading budget under § 96.140 (except as provided in paragraph (d) of this section).

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(2) The permitting authority will allocate CAIR NO_X allowances to each CAIR NO_X unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO_X allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO_X unit to the total amount of baseline heat input of all such CAIR NO_X units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NO_X allowances to CAIR NO_X units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO_X allowances equal to 5 percent for a control period in 2009 through 2013, and 3 percent for a control period in 2014 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.140.

(2) The CAIR designated representative of such a CAIR NO_X unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NO_X allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO_X unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO_X allowances under paragraph (b) of this section. The CAIR NO_X allowance allocation request must be submitted on or before July 1 of the first control period for which the CAIR NO_X allowances are requested and after the date on which the CAIR NO_X unit commences commercial operation.

(3) In a CAIR NO_X allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO_X allowances in an amount not exceeding the CAIR NO_X unit's total tons of NO_X emissions during the calendar year immediately before such control period.

(4) The permitting authority will review each CAIR NO_X allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NO_X allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after July 1 of the control period, the permitting authority will determine the sum of the CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NO_X allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NO_X unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NO_X allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each CAIR NO_X unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NO_X allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NO_X allowances (if any) allocated for the control period to the CAIR NO_X unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NO_X allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NO_X unit that was allocated CAIR NO_X allowances under paragraph (b) of this section an amount of CAIR NO_X allowances equal to the total amount of such remaining unallocated CAIR NO_X allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.140, and rounded to the nearest whole allowance as appropriate.

§ 96.143 Compliance supplement pool.

(a) In addition to the CAIR NO_X allowances allocated under § 96.142, the permitting authority may allocate for the control period in 2009 up to the following amount of CAIR NO_X allowances to CAIR NO_X units in the respective State:

State	Compliance supplement pool
Alabama	10,166
District Of Columbia	0
Florida	8,335
Georgia	12,397
Illinois	11,299
Indiana	20,155
Iowa	6,978
Kentucky	14,935
Louisiana	2,251
Maryland	4,670
Michigan	8,347
Minnesota	6,528
Mississippi	3,066
Missouri	9,044
New York	0
North Carolina	0
Ohio	25,037
Pennsylvania	16,009
South Carolina	2,600
Tennessee	8,944
Texas	772
Virginia	5,134
West Virginia	16,929
Wisconsin	4,898

(b) For any CAIR NO_X unit in the State that achieves NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable during such years, the CAIR designated representative of the unit may request early reduction credits, and allocation of CAIR NO_X allowances from the compliance supplement pool under paragraph (a) of this section for such early reduction credits, in accordance with the following:

(1) The owners and operators of such CAIR NO_X unit shall monitor and report the NO_X emissions rate and the heat input of the unit in accordance with subpart HH of this part in each control period for which early reduction credit is requested.

(2) The CAIR designated representative of such CAIR NO_X unit shall submit to the permitting authority by July 1, 2009 a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NO_X allowances from the compliance supplement pool not exceeding the sum of the amounts (in tons) of the unit's

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NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable during such years, determined in accordance with subpart HH of this part.

(c) For any CAIR NO_X unit in the State whose compliance with CAIR NO_X emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period, the CAIR designated representative of the unit may request the allocation of CAIR NO_X allowances from the compliance supplement pool under paragraph (a) of this section, in accordance with the following:

(1) The CAIR designated representative of such CAIR NO_X unit shall submit to the permitting authority by July 1, 2009 a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NO_X allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NO_X allowances necessary to remove such undue risk to the reliability of electricity supply.

(2) In the request under paragraph (c)(1) of this section, the CAIR designated representative of such CAIR NO_X unit shall demonstrate that, in the absence of allocation to the unit of the amount of CAIR NO_X allowances requested, the unit's compliance with CAIR NO_X emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period. This demonstration must include a showing that it would not be feasible for the owners and operators of the unit to:

(i) Obtain a sufficient amount of electricity from other electricity generation facilities, during the installation of control technology at the unit for compliance with the CAIR NO_X emissions limitation, to prevent such undue risk; or

(ii) Obtain under paragraphs (b) and (d) of this section, or otherwise obtain, a sufficient amount of CAIR NO_X allowances to prevent such undue risk.

(d) The permitting authority will review each request under paragraph (b) or (c) of this section submitted by July 1, 2009 and will allocate CAIR NO_X allowances for the control period in 2009 to CAIR NO_X units in the State and covered by such request as follows:

(1) Upon receipt of each such request, the permitting authority will make any necessary adjustments to the request to ensure that the amount of the CAIR NO_X allowances requested meets the requirements of paragraph (b) or (c) of this section.

(2) If the State's compliance supplement pool under paragraph (a) of this section has an amount of CAIR NO_X allowances not less than the total amount of CAIR NO_X allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate to each CAIR NO_X unit covered by such requests the amount of CAIR NO_X allowances requested (as adjusted under paragraph (d)(1) of this section).

(3) If the State's compliance supplement pool under paragraph (a) of this section has a smaller amount of CAIR NO_X allowances than the total amount of CAIR NO_X allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate CAIR NO_X allowances to each CAIR NO_X unit covered by such requests according to the following formula and rounding to the nearest whole allowance as appropriate:

Unit's allocation = Unit's adjusted allocation × (State's compliance supplement pool ÷ Total adjusted allocations for all units)

Where:

''Unit's allocation'' is the number of CAIR NO_X allowances allocated to the unit from the State's compliance supplement pool. Unit's adjusted allocation'' is the amount of CAIR NO_X allowances requested for the unit under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section. ''State's compliance supplement pool'' is the amount of CAIR NO_X allowances in the State's compliance supplement pool. ''Total adjusted allocations for all units'' is the sum of the amounts of allocations requested for all units under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section.

(4) By November 30, 2009, the permitting authority will determine, and submit to the Administrator, the allocations under paragraph (d)(3) or (4) of this section.

(5) By January 1, 2010, the Administrator will record the allocations under paragraph (d)(5) of this section.

Subpart FF—CAIR NO_X Allowance Tracking System

§ 96.150 [Reserved]

§ 96.151 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.184(e), upon receipt of a complete certificate of representation under § 96.113, the Administrator will establish a compliance account for the CAIR NO_X source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) General accounts. (1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO_X allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO_X allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO_X allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO_X allowances held in the general account in all matters pertaining to the CAIR NO_X Annual Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO_X allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO_X allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR NO_X allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO_X allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO_X allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO_X Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NO_X allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

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§ 96.152 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO_X Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO_X allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.153 Recordation of CAIR NO_X allowance allocations.

(a) By December 1, 2006, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at a source, as submitted by the permitting authority in accordance with § 96.141(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with § 96.141(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a CAIR NO_X source's compliance account under § 96.154, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.141(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By December 1, 2009 and December 1 of each year thereafter, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated CAIR NO_X allowances. When recording the allocation of CAIR NO_X* allowances for a CAIR NO_X unit in a compliance account, the Administrator will assign each CAIR NO_X allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO_X allowance is allocated.

§ 96.154 Compliance with CAIR NO_X emissions limitation.

(a) *Allowance transfer deadline.* The CAIR NO_X allowances are available to be deducted for compliance with a source's CAIR NO_X emissions limitation for a control period in a given calendar year only if the CAIR NO_X allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO_X allowance transfer correctly submitted for recordation under § 96.160 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.161, of CAIR NO_X allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NO_X allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NO_X emissions limitation for the control period, as follows:

(1) Until the amount of CAIR NO_X allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HH of this part, from all CAIR NO_X units at the source for the control period; or

(2) If there are insufficient CAIR NO_X allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NO_X allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CAIR NO_X allowances by serial number. The CAIR authorized account representative for a source's compliance account may request that specific CAIR NO_X* allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO_X source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR NO_X allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR NO_X allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NO_X allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NO_X allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to subpart GG of this part, in the order of recordation.

(d) Deductions for excess emissions.

(1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NO_X source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CAIR NO_X allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NO_X source or the CAIR NO_X units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) Administrator's action on submissions.

(1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NO_X Annual Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NO_X allowances from or transfer CAIR NO_X allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.155 Banking.

(a) CAIR NO_X allowances may be banked for future use or transfer in a compliance account or a general

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account in accordance with paragraph (b) of this section.

(b) Any CAIR NO_X allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NO_X allowance is deducted or transferred under § 96.154, § 96.156, or subpart GG of this part.

§ 96.156 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO_X Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.157 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.160 for any CAIR NO_X allowances in the account to one or more other CAIR NO_X Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO_X allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO_X allowances into the account under § 96.160 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GG—CAIR NO_X Allowance Transfers

§ 96.160 Submission of CAIR NO_X allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO_X allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO_X allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO_X allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.161 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO_X allowance transfer, the Administrator will record a CAIR NO_X allowance transfer by moving each CAIR NO_X allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.160; and

(2) The transferor account includes each CAIR NO_X allowance identified by serial number in the transfer.

(b) A CAIR NO_X allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO_X allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.154 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO_X allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.162 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR NO_X allowance transfer under § 96.161, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR NO_X allowance transfer that fails to meet the requirements of § 96.161(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO_X allowance transfer for recordation following notification of non-recordation.

Subpart HH—Monitoring and Reporting

§ 96.170 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO_X unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.102 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR NO_X unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.102. The owner or operator of a unit that is not a CAIR NO_X unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO_X unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR NO_X unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 96.171 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO_X unit that commences commercial operation before July 1, 2007, by January 1, 2008.

(2) For the owner or operator of a CAIR NO_X unit that commences commercial operation on or after July 1, 2007, by the later of the following dates:

(i) January 1, 2008; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR NO_X unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, by the date specified in § 96.184(b).

(5) Notwithstanding the dates in paragraphs (b)(1), (2), and (4) of this section and solely for purposes of § 96.106(c)(2), for the owner or operator of a CAIR NO_X opt-in unit under subpart II of this part, by the date on which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program as provided in § 96.184(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR NO_X unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.175.

(2) No owner or operator of a CAIR NO_X unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NO_X unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NO_X unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.105 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.171(d)(3)(i).

§ 96.171 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO_X unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12, § 75.17, or subpart H of part 75 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.175(a) to determine whether the approval applies under the CAIR NO_X Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO_X unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.*, a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 96.170(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.170(a)(1)(including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission

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monitoring system under § 96.170(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 96.170(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.170(a)(1). For recertifications, replace the words ''certification'' and ''initial certification'' with the word ''recertification'', replace the word ''certified'' with the word ''recertified,'' and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.173.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO_X Annual Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) *Certification application approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NO_X Annual Trading Program.

(A) *Approval notice*. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice*. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.172(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NO_X emission rate (*i.e.*, NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(2) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2

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concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's or the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) *Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter.* The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) *Certification/recertification procedures for alternative monitoring systems.* The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.172 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.171 for each disapproved monitoring system.

§ 96.173 Notifications.

The CAIR designated representative for a CAIR NO_X unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 96.174 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 96.110(e)(1).

(b) *Monitoring Plans.* The owner or operator of a CAIR NO_X unit shall comply with requirements of § 75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, §§ 96.183 and 96.184(a).

(c) *Certification Applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.171, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) The CAIR designated representative shall report the NO_X mass emissions data and heat input data for the CAIR NO_X unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering January 1, 2008 through March 31, 2008; or

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.170(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering January 1, 2008 through March 31, 2008.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For CAIR NO_X units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Ozone Season Trading Program or CAIR SO_2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions.

§ 96.175 Petitions.

(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO_X unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO_X unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO_X unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional continuous emission monitoring system required under § 75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.176 Additional requirements to provide heat input data.

The owner or operator of a CAIR NO_X unit that monitors and reports NO_X mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart II—CAIR NO_X Opt-in Units

§ 96.180 Applicability.

A CAIR NO_X opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR NO_X unit under § 96.104 and is not covered by a retired unit exemption under § 96.105 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HH of this part.

§ 96.181 General.

(a) Except as otherwise provided in §§ 96.101 through 96.104, §§ 96.106 through 96.108, and subparts BB and CC and subparts FF through HH of this part, a CAIR NO_X opt-in unit shall be treated as a CAIR NO_X unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO_X unit before issuance of a CAIR opt-in permit for such unit.

§ 96.182 CAIR designated representative.

Any CAIR NO_X opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO_X units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO_X units.

§ 96.183 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR NO_X opt-in unit in § 96.180 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.186(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 96.122;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR NO_X unit under § 96.104 and is not covered by a retired unit exemption under § 96.105 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack, and

(iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 96.122;

(3) A monitoring plan in accordance with subpart HH of this part;

(4) A complete certificate of representation under § 96.113 consistent with § 96.182, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO_X allowances under § 96.188(c) (subject to the conditions in §§ 96.184(h) and 96.186(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR NO_X opt-in unit shall submit a complete CAIR permit application under § 96.122 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or the permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR NO_X Annual Trading Program in accordance with § 96.186 or the unit becomes a CAIR NO_X unit under § 96.104, the CAIR NO_X opt-in unit shall remain subject to the requirements for a CAIR NO_X opt-in unit, even if the CAIR designated representative for the CAIR NO_X opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.184 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.183 is submitted in accordance with the following:

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.183. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO_X emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HH of this part and continuing until a CAIR opt-in permit is denied under § 96.184(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO_X Annual Trading Program in accordance with § 96.186.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), during which period monitoring system availability must not be less than 90 percent under subpart HH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and for the control periods under paragraph (b)(2) of this section.

(d) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's NO_X emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for such control period during which the unit has add-on NO_X emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO_X opt-in unit in § 96.180 and meets the elements certified in § 96.183(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO_X opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO_X opt-in unit in § 96.180 or meets the elements certified in § 96.183(a)(2), the permitting authority will issue a denial of a CAIR NO_X opt-in permit for the unit.

(g) *Date of entry into CAIR NO_X Annual Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NO_X opt-in unit, and a CAIR NO_X unit, as of the later of January 1, 2009 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) *Repowered CAIR NO_X opt-in unit.* (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X opt-in unit of CAIR NO_X allowances under § 96.188(c) and such unit is repowered after its date of entry into the CAIR NO_X Annual Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO_X opt-in unit replacing the original CAIR NO_X opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO_X emission rate as the original CAIR NO_X opt-in unit, and the original CAIR NO_X opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR NO_X unit.

§ 96.185 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.122;

(2) The certification in § 96.183(a)(2);

(3) The unit's baseline heat input under § 96.184(c);

(4) The unit's baseline NO_X emission rate under § 96.184(d);

(5) A statement whether the unit is to be allocated CAIR NO_X allowances under § 96.188(c) (subject to the

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conditions in §§ 96.184(h) and 96.186(g));

(6) A statement that the unit may withdraw from the CAIR NO_X Annual Trading Program only in accordance with § 96.186; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.187.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.102 and, upon recordation by the Administrator under subpart FF or GG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO_X allowances to or from the compliance account of the source that includes a CAIR NO_X opt-in unit covered by the CAIR opt-in permit.

§ 96.186 Withdrawal from CAIR NO_X Annual Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO_X opt-in unit may withdraw from the CAIR NO_X Annual Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO_X opt-in unit of the acceptance of the withdrawal of the CAIR NO_X opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR NO_X Annual Trading Program, the CAIR designated representative of the CAIR NO_X opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR NO_X Annual Trading Program under § 96.184(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR NO_X opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO_X Annual Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO_X opt-in unit must meet the requirement to hold CAIR NO_X allowances under § 96.106(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO_X opt-in unit CAIR NO_X allowances equal in number to and allocated for the same or a prior control period as any CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO_X units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NO_X opt-in unit may submit a CAIR NO_X allowance transfer for any remaining CAIR NO_X allowances to another CAIR NO_X Allowance Tracking System in accordance with subpart GG of this part.

(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO_X allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X opt-in unit of the acceptance of the withdrawal of the CAIR NO_X opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X opt-in unit that the CAIR NO_X opt-in unit's request to withdraw is denied. Such CAIR NO_X opt-in unit shall continue to be a CAIR NO_X opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO_X opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO_X opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO_X Annual Trading Program concerning any control periods for which the unit is a CAIR NO_X opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the CAIR NO_X opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) *Ability to reapply to the CAIR NO_X Annual Trading Program.* Once a CAIR NO_X opt-in unit withdraws from the CAIR NO_X Annual Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.183 for such CAIR NO_X opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt- in permit under § 96.184.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO_X opt-in unit shall not be eligible to withdraw from the CAIR NO_X Annual Trading Program if the CAIR designated representative of the CAIR NO_X opt-in unit requests, and the permitting authority issues a CAIR NO_X opt-in permit providing for, allocation to the CAIR NO_X opt-in unit of CAIR NO_X allowances under § 96.188(c).

§ 96.187 Change in regulatory status.

(a) *Notification.* If a CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO_X opt-in unit's regulatory status, within 30 days of such change.

(b) Permitting authority's and Administrator's actions.

(1) If a CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, the permitting authority will revise the CAIR NO_X opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.123 as of the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO_X opt-in unit that becomes a CAIR NO_X unit under § 96.104, CAIR NO_X allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for any control period after the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104; and

(B) If the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 is not December 31, the CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for the control period that includes the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under

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§ 96.104, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO_X unit that becomes a CAIR NO_X unit under § 96.104 contains the CAIR NO_X allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, the CAIR NO_X opt-in unit will be treated, solely for purposes of CAIR NO_X allowance allocations under § 96.142, as a unit that commences operation on the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 and will be allocated CAIR NO_X allowances under § 96.142.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 is not January 1, the following number of CAIR NO_X allowances will be allocated to the CAIR NO_X opt-in unit (as a CAIR NO_X unit) under § 96.142 for the control period that includes the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104:

(A) The number of CAIR NO_X allowances otherwise allocated to the CAIR NO_X opt-in unit (as a CAIR NO_X unit) under § 96.142 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.188 NO_X allowance allocations to CAIR NO_X opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.184(e), the permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO_X opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NO_X allowance allocation will be the lesser of:

(i) The CAIR NO_X opt-in unit's baseline heat input determined under § 96.184(c); or

(ii) The CAIR NO_X opt-in unit's heat input, as determined in accordance with subpart HH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X allowance allocations will be the lesser of:

(i) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period for which CAIR NO_X allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X opt-in unit of CAIR NO_X allowances under this paragraph (subject to the conditions in §§ 96.184(h) and 96.186(g)), the permitting authority will allocate to the CAIR NO_X opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO_X allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X allowance allocations will be the lesser of:

(A) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d); or

(B) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period in which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g).

(iii) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO_X allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating the CAIR NO_X allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d); or

(C) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period for which CAIR NO_X allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that

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includes the CAIR NO_X opt-in unit, the CAIR NO_X allowances allocated by the permitting authority to the CAIR NO_X opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NO_X opt-in unit, the CAIR NO_X allowances allocated by the permitting authority to the CAIR NO_X opt-in unit under paragraph (a)(2) of this section.

■ 3. Part 96 is amended by adding subparts AAA through CCC, adding and reserving subparts DDD and EEE and adding subparts FFF through III to read as follows:

Subpart AAA—CAIR SO_2 Trading Program General Provisions

§ 96.201 Purpose.

This subpart and subparts BBB through III establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) SO_2 Trading Program, under section 110 of the Clean Air Act and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBB through III as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.124(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR SO_2 Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.202 Definitions.

The terms used in this subpart and subparts BBB through III shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR SO_2 Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means, with regard to CAIR SO_2 allowances issued under the Acid Rain Program, the determination by the Administrator of the amount of such CAIR SO_2 allowances to be initially credited to a CAIR SO_2 unit and, with regard to CAIR SO_2 allowances issued under § 96.288, the determination by the permitting authority of the amount of such CAIR SO_2 allowances to be initially credited to a CAIR SO_2 unit.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR SO_2 allowance transfer must be submitted for recordation in a CAIR SO_2 source's compliance account in order to be used to meet the source's CAIR SO_2 emissions limitation for such control period in accordance with §96.254.

Alternate CAIR designated representative means, for a CAIR SO_2 source and each CAIR SO_2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BBB and III of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR SO_2 Trading Program. If the CAIR SO_2 source is also a CAIR NO_X source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR SO_2 source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR SO_2 source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBB and III of this part, to transfer and otherwise dispose of CAIR SO_2 allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR SO_2 source and each CAIR SO_2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBB and III of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR SO_2 Trading Program. If the CAIR SO_2 source is also a CAIR NO_X source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR SO_2 source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR SO_2 source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCC of this part, including any permit revisions, specifying the CAIR SO_2 Trading Program requirements applicable to a CAIR SO_2 source, to each CAIR SO_2 unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 allowance means a limited authorization issued by the Administrator under the Acid Rain Program, or by a permitting authority under § 96.288, to emit sulfur dioxide during the control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR SO_2 Trading Program as follows:

(1) For one CAIR SO_2 allowance allocated for a control period in a year before 2010, one ton of sulfur dioxide, except as provided in § 96.254(b);

(2) For one CAIR SO_2 allowance allocated for a control period in 2010 through 2014, 0.50 ton of sulfur dioxide, except as provided in § 96.254(b); and

(3) For one CAIR SO_2 allowance allocated for a control period in 2015 or later, 0.35 ton of sulfur dioxide, except as provided in § 96.254(b).

An authorization to emit sulfur dioxide that is not issued under the Acid Rain Program or under the provisions of a State implementation plan that is approved under § 51.124(o)(1) or (2) of this chapter shall not be a CAIR SO_2 allowance.

CAIR SO_2 allowance deduction or *deduct CAIR SO_2 allowances* means the permanent withdrawal of CAIR SO_2 allowances by the Administrator from a compliance account in order to account for a specified number of tons of total sulfur dioxide emissions from all CAIR SO_2 units at a CAIR SO_2 source for a control period, determined in accordance with subpart HHH of this part, or to account for excess emissions.

CAIR SO_2 Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR SO_2 allowances under the CAIR SO_2 Trading Program. This is the same system as the Allowance Tracking System under § 72.2 of this chapter by which the Administrator records allocations, deduction, and transfers of Acid Rain SO_2 allowances under the Acid Rain Program.

CAIR SO_2 Allowance Tracking System account means an account in the CAIR SO_2 Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR SO_2 allowances. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR SO_2 allowances held or *hold CAIR SO_2 allowances* means the CAIR SO_2 allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFF, GGG, and III of this part or part 73 of this chapter, in a CAIR SO_2 Allowance Tracking System account.

CAIR SO_2 emissions limitation means, for a CAIR SO_2 source, the tonnage equivalent of the CAIR SO_2 allowances available for deduction for the source under § 96.254(a) and (b) for a control period.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

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CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and, except for purposes of § 96.205, a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone, or in combination with any amount of any other fuel.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.205.

(i) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.205, for a unit that is not a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR SO_2 unit under § 96.204.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.284(h) or § 96.287(b)(3), for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the SO_2 emissions rate and the heat input of the unit under § 96.284(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.205.

(i) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.205, for a unit that is not a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR SO_2 unit under § 96.204.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such

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date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1),(2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.284(h) or § 96.287(b)(3), for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the SO_2 emissions rate and the heat input of the unit under § 96.284(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR SO_2 Allowance Tracking System account, established by the Administrator for a CAIR SO_2 source subject to an Acid Rain emissions limitations under § 73.31(a) or (b) of this chapter or for any other CAIR SO_2 source under subpart FFF or III of this part, in which any CAIR SO_2 allowance allocations for the CAIR SO_2 units at the source are initially recorded and in which are held any CAIR SO_2 allowances available for use for a control period in order to meet the source's CAIR SO_2 emissions limitation in accordance with § 96.254.

Continuous emission monitoring system or *CEMS* means the equipment required under subpart HHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of sulfur dioxide emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HHH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A sulfur dioxide monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2 in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHH of this part.

Excess emissions means any ton, or portion of a ton, of sulfur dioxide emitted by the CAIR SO_2 units at a CAIR SO_2 source during a control period that exceeds the CAIR SO_2 emissions limitation for the source, provided that any portion of a ton of excess emissions shall be treated as one ton of excess emissions.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

General account means a CAIR SO_2 Allowance Tracking System account, established under subpart FFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of

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combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal SO_2 emissions limitation means, with regard to a unit, the lowest SO_2 emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a CAIR SO_2 unit or a CAIR SO_2 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR SO_2 source or a CAIR SO_2 unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR SO_2 unit at the source or the CAIR SO_2 unit;

(ii) Any holder of a leasehold interest in a CAIR SO_2 unit at the source or the CAIR SO_2 unit; or

(iii) Any purchaser of power from a CAIR SO_2 unit at the source or the CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR SO_2 unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR SO_2 allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR SO_2 allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR SO_2 Trading Program in accordance with subpart CCC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CAIR SO_2 allowances, the movement of CAIR SO_2 allowances by the Administrator into or between CAIR SO_2 Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR SO_2 allowance, the unique identification number assigned to each CAIR SO_2 allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the States or the District of Columbia that adopts the CAIR SO_2 Trading Program pursuant to § 51.124 (o)(1) or (2) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR SO_2 emissions limitation, total tons of sulfur dioxide emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.203 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu-British thermal unit.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
hr—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
mmBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
O_2—oxygen.
ppm—parts per million.
lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr—year.

§ 96.204 Applicability.

The following units in a State shall be CAIR SO_2 units, and any source that includes one or more such units shall be a CAIR SO_2 source, subject to the requirements of this subpart and subparts BBB through HHH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.205 Retired unit exemption.

(a)(1) Any CAIR SO_2 unit that is permanently retired and is not a CAIR SO_2 opt-in unit under subpart III of this part shall be exempt from the CAIR SO_2 Trading Program, except for the provisions of this section, § 96.202, § 96.203, § 96.204, § 96.206(c)(4) through (8), § 96.207, and subparts FFF and GGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR SO_2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CCC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any sulfur dioxide, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.222 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(5) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(4) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(4) of this section to submit a CAIR permit application for the unit; or

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(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(6) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.206 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR SO_2 source required to have a title V operating permit and each CAIR SO_2 unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.222 in accordance with the deadlines specified in § 96.221(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR SO_2 source required to have a title V operating permit and each CAIR SO_2 unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart III of this part, the owners and operators of a CAIR SO_2 source that is not otherwise required to have a title V operating permit and each CAIR SO_2 unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCC of this part for such CAIR SO_2 source and such CAIR SO_2 unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the CAIR designated representative, of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO_2 source with the CAIR SO_2 emissions limitation under paragraph (c) of this section.

(c) *Sulfur dioxide emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO_2 allowances available for compliance deductions for the control period, as determined in accordance with § 96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with subpart HHH of this part.

(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under § 96.270(b)(1),(2), or (5).

(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with subparts FFF and GGG of this part.

(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR SO_2 allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO_2 unit.

(d) *Excess emissions requirements*—(1) If a CAIR SO_2 source emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation, then:

(i) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under § 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.213 for the CAIR designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO_2 Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO_2 Trading Program.

(2) The CAIR designated representative of a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR SO_2 Trading Program, including those under subpart HHH of this part.

(f) *Liability.* (1) Each CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program.

(2) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 source or the CAIR designated representative of a CAIR SO_2 source shall also apply to the owners and operators of such source and of the CAIR SO_2 units at the source.

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(3) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 unit or the CAIR designated representative of a CAIR SO_2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR SO_2 Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.207 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR SO_2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR SO_2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR SO_2 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.208 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR SO_2 Trading Program are set forth in part 78 of this chapter.

Subpart BBB—CAIR Designated Representative for CAIR SO_2 Sources

§ 96.210 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.211, each CAIR SO_2 source, including all CAIR SO_2 units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR SO_2 Trading Program concerning the source or any CAIR SO_2 unit at the source.

(b) The CAIR designated representative of the CAIR SO_2 source shall be selected by an agreement binding on the owners and operators of the source and all CAIR SO_2 units at the source and shall act in accordance with the certification statement in § 96.213(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.213, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR SO_2 source represented and each CAIR SO_2 unit at the source in all matters pertaining to the CAIR SO_2 Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR SO_2 Allowance Tracking System account will be established for a CAIR SO_2 unit at a source, until the Administrator has received a complete certificate of representation under § 96.213 for a CAIR designated representative of the source and the CAIR SO_2 units at the source.

(e)(1) Each submission under the CAIR SO_2 Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR SO_2 source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR SO_2 source or a CAIR SO_2 unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.211 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.213 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.213, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.202, 96.210(a) and (d), 96.212, 96.213, 96.251, and 96.282, whenever the term ''CAIR designated representative'' is used in subparts AAA through III of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR SO_2 source and the CAIR SO_2 units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO_2 source and the CAIR SO_2 units at the source.

(c) Changes in owners and operators. (1) In the event a new owner or operator of a CAIR SO_2 source or a CAIR SO_2 unit

is not included in the list of owners and operators in the certificate of representation under § 96.213, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR SO_2 source or a CAIR SO_2 unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.213 amending the list of owners and operators to include the change.

§ 96.213 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR SO_2 source, and each CAIR SO_2 unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR SO_2 source and of each CAIR SO_2 unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR SO_2 unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program on behalf of the owners and operators of the source and of each CAIR SO_2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR SO_2 unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO_2 unit, or where a customer purchases power from a CAIR SO_2 unit under a life-of- the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR SO_2 unit at the source; and CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO_2 allowances by contract, CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.214 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.213 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.213 is received by the Administrator.

(b) Except as provided in § 96.212(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR SO_2 Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR SO_2 allowance transfers.

Subpart CCC—Permits

§ 96.220 General CAIR SO_2 Trading Program permit requirements.

(a) For each CAIR SO_2 source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR SO_2 source and the CAIR SO_2 units at the source, all applicable CAIR SO_2 Trading Program, CAIR NO_X Annual Trading Program, and CAIR NO_X Ozone Season Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.221 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR SO_2 source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.222 for the source covering each CAIR SO_2 unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the CAIR SO_2 unit commences operation.

(b) *Duty to Reapply.* For a CAIR SO_2 source required to have a title V operating permit, the CAIR designated

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representative shall submit a complete CAIR permit application under § 96.222 for the source covering each CAIR SO_2 unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.222 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR SO_2 source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR SO_2 source;

(b) Identification of each CAIR SO_2 unit at the CAIR SO_2 source; and

(c) The standard requirements under § 96.206.

§ 96.223 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.222.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.202 and, upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from the compliance account of the CAIR SO_2 source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR SO_2 source's title V operating permit or other federally enforceable permit as applicable.

§ 96.224 CAIR permit revisions.

Except as provided in § 96.223(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDD—[Reserved]

Subpart EEE—[Reserved]

Subpart FFF—CAIR SO_2 Allowance Tracking System

§ 96.250 [Reserved]

§ 96.251 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.284(e), upon receipt of a complete certificate of representation under § 96.213, the Administrator will establish a compliance account for the CAIR SO_2 source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) *General accounts*—(1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR SO_2 allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR SO_2 allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR SO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR SO_2 allowances held in the general account in all matters pertaining to the CAIR SO_2 Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR SO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR SO_2 allowances held

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in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO_2 allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO_2 allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR SO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR SO_2 allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR SO_2 allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR SO_2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR SO_2 allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.252 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR SO_2 Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR SO_2 allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.253 Recordation of CAIR SO_2 allowances.

(a)(1) After a compliance account is established under § 96.251(a) or § 73.31(a) or (b) of this chapter, the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under § 96.254(b), the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are or could be made) and any CAIR SO_2 allowance allocated for the new 30th year and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(b)(1) After a general account is established under § 96.251(b) or § 73.31(c) of this chapter, the Administrator will record in the general account any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the general account is established and transferred to the general account in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under § 96.254(b), the Administrator will record in the general account any CAIR SO_2 allowance allocated for the new 30th year (*i.e.*, the year that is 30 years after the calendar

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year for which such deductions are or could be made) and transferred to the general account in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(c) *Serial numbers for allocated CAIR SO_2 allowances.* When recording the allocation of CAIR SO_2 allowances issued by a permitting authority under § 96.288, the Administrator will assign each such CAIR SO_2 allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR SO_2 allowance is allocated.

§ 96.254 Compliance with CAIR SO_2 emissions limitation.

(a) *Allowance transfer deadline.* The CAIR SO_2 allowances are available to be deducted for compliance with a source's CAIR SO_2 emissions limitation for a control period in a given calendar year only if the CAIR SO_2 allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR SO_2 allowance transfer correctly submitted for recordation under § 96.260 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deduction for excess emissions for a prior control period under paragraph (d) of this section or for deduction under part 77 of this chapter.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.261, of CAIR SO_2 allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR SO_2 allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period as follows:

(1) For a CAIR SO_2 source subject to an Acid Rain emissions limitation, the Administrator will, in the following order:

(i) Deduct the amount of CAIR SO_2 allowances, available under paragraph (a) of this section and not issued by a permitting authority under § 96.288, that is required under §§ 73.35(b) and (c) of this part. If there are sufficient CAIR SO_2 allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(b) and (c) of this chapter.

(ii) Deduct the amount of CAIR SO_2 allowances, available under paragraph (a) of this section and not issued by a permitting authority under § 96.288, that is required under §§ 73.35(d) and 77.5 of this part. If there are sufficient CAIR SO_2 allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(d) and 77.5 of this chapter.

(iii) Treating the CAIR SO_2 allowances deducted under paragraph (b)(1)(i) of this section as also being deducted under this paragraph (b)(1)(iii), deduct CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period, as follows:

(A) Until the tonnage equivalent of the CAIR SO_2 allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO_2 units at the source for the control period; or

(B) If there are insufficient CAIR SO_2 allowances to complete the deductions in paragraph (b)(1)(iii)(A) of this section, until no more CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) remain in the compliance account.

(2) For a CAIR SO_2 source not subject to an Acid Rain emissions limitation, the Administrator will deduct CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under §96.288) in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period, as follows:

(i) Until the tonnage equivalent of the CAIR SO_2 allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO_2 units at the source for the control period; or

(ii) If there are insufficient CAIR SO_2 allowances to complete the deductions in paragraph (b)(2)(i) of this section, until no more CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) remain in the compliance account.

(c)(1) *Identification of CAIR SO_2 allowances by serial number.* The CAIR authorized account representative for a source's compliance account may request that specific CAIR SO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR SO_2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR SO_2 allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR SO_2 allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period before 2010, in the order of recordation;

(ii) Any CAIR SO_2 allowances that were allocated to any unit for a control period before 2010 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(iii) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period during 2010 through 2014, in the order of recordation;

(iv) Any CAIR SO_2 allowances that were allocated to any unit for a control period during 2010 through 2014 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(v) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period in 2015 or later, in the order of recordation; and

(vi) Any CAIR SO_2 allowances that were allocated to any unit for a control period in 2015 or later and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR SO_2 source has excess emissions, the Administrator will deduct from the source's compliance account the tonnage equivalent in CAIR SO_2 allowances, allocated for the control period in the immediately following calendar year (including any issued by a permitting authority under § 96.288), equal to, or exceeding in

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accordance with paragraphs (c)(1) and (2) of this section, 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR SO_2 source or the CAIR SO_2 units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR SO_2 Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR SO_2 allowances from or transfer CAIR SO_2 allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.255 Banking.

(a) CAIR SO_2 allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR SO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR SO_2 allowance is deducted or transferred under § 96.254, § 96.256, or subpart GGG of this part.

§ 96.256 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR SO_2 Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.257 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.260 for any CAIR SO_2 allowances in the account to one or more other CAIR SO_2 Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR SO_2 allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR SO_2 allowances into the account under § 96.260 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGG—CAIR SO_2 Allowance Transfers

§ 96.260 Submission of CAIR SO_2 allowance transfers.

(a) A CAIR authorized account representative seeking recordation of a CAIR SO_2 allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR SO_2 allowance transfer shall include the following elements, in a format specified by the Administrator:

(1) The account numbers of both the transferor and transferee accounts;

(2) The serial number of each CAIR SO_2 allowance that is in the transferor account and is to be transferred; and

(3) The name and signature of the CAIR authorized account representatives of the transferor and transferee accounts and the dates signed.

(b)(1) The CAIR authorized account representative for the transferee account can meet the requirements in paragraph (a)(3) of this section by submitting, in a format prescribed by the Administrator, a statement signed by the CAIR authorized account representative and identifying each account into which any transfer of allowances, submitted on or after the date on which the Administrator receives such statement, is authorized. Such authorization shall be binding on any CAIR authorized account representative for such account and shall apply to all transfers into the account that are submitted on or after such date of receipt, unless and until the Administrator receives a statement signed by the CAIR authorized account representative retracting the authorization for the account.

(2) The statement under paragraph (b)(1) of this section shall include the following: ''By this signature I authorize any transfer of allowances into each account listed herein, except that I do not waive any remedies under State or Federal law to obtain correction of any erroneous transfers into such accounts. This authorization shall be binding on any CAIR authorized account representative for such account unless and until a statement signed by the CAIR authorized account representative retracting this authorization for the account is received by the Administrator.''

§ 96.261 EPA recordation.

(a) Within 5 business days (except as necessary to perform a transfer in perpetuity of CAIR SO_2 allowances allocated to a CAIR SO_2 unit or as provided in paragraph (b) of this section) of receiving a CAIR SO_2 allowance transfer, the Administrator will record a CAIR SO_2 allowance transfer by moving each CAIR SO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.260; and

(2) The transferor account includes each CAIR SO_2 allowance identified by serial number in the transfer.

(b) A CAIR SO_2 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR SO_2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.254 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR SO_2 allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.262 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR SO_2 allowance transfer under § 96.261, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR SO_2 allowance transfer that fails to meet the requirements of § 96.261(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR SO_2 allowance transfer for recordation following notification of non-recordation.

Subpart HHH—Monitoring and Reporting

§ 96.270 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR SO_2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subparts F and G of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.202 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR SO_2 unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.202. The owner or operator of a unit that is not a CAIR SO_2 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR SO_2 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR SO_2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 96.271 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR SO_2 unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a CAIR SO_2 unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR SO_2 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, by the date specified in § 96.284(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section and solely for purposes of § 96.206(c)(2), for the owner or operator of a CAIR SO_2 opt-in unit under subpart III of this part, by the date on which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program as provided in § 96.284(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR SO_2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, SO_2 emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR SO_2 unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D of or appendix D to part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR SO_2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.275.

(2) No owner or operator of a CAIR SO_2 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR SO_2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR SO_2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.205 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.271(d)(3)(i).

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§ 96.271 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR SO_2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.270(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B and appendix D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.270(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §§ 75.16(b)(2)(ii) of this chapter for apportioning the SO_2 mass emissions measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.11 or § 75.16 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.275(a) to determine whether the approval applies under the CAIR SO_2 Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR SO_2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.*, a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 96.270(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.270(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.270(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 96.270(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 96.270(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.270(a)(1). For recertifications, replace the words ''certification'' and ''initial certification'' with the word ''recertification'', replace the word ''certified'' with the word ''recertified,'' and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.273.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR SO_2 Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) *Certification application approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR SO_2 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.272(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*2*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*3*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's or the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) Certification/recertification procedures for alternative monitoring systems. The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.272 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D of or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.271 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.271 for each disapproved monitoring system.

§ 96.273 Notifications.

The CAIR designated representative for a CAIR SO_2 unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 96.274 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 96.210(e)(1).

(b) *Monitoring plans.* The owner or operator of a CAIR SO_2 unit shall comply with requirements of § 75.62 of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, §§ 96.283 and 96.284(a).

(c) *Certification applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.271, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) The CAIR designated representative shall report the SO_2 mass emissions data and heat input data for the CAIR SO_2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.270(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For CAIR SO_2 units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program or CAIR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 96.275 Petitions.

(a) The CAIR designated representative of a CAIR SO_2 unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b) The CAIR designated representative of a CAIR SO_2 unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.276 Additional requirements to provide heat input data.

The owner or operator of a CAIR SO_2 unit that monitors and reports SO_2 mass emissions using a SO_2 concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart III—CAIR SO_2 Opt-in Units

§ 96.280 Applicability.

A CAIR SO_2 opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR SO_2 unit under § 96.204 and is not covered by a retired unit exemption under § 96.205 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect and is not an opt-in source under part 74 of this chapter;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHH of this part.

§ 96.281 General.

(a) Except as otherwise provided in §§ 96.201 through 96.204, §§ 96.206 through 96.208, and subparts BBB and CCC and subparts FFF through HHH of this part, a CAIR SO_2 opt-in unit shall be treated as a CAIR SO_2 unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR SO_2 unit before issuance of a CAIR opt-in permit for such unit.

§ 96.282 CAIR designated representative.

Any CAIR SO_2 opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR SO_2 units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR SO_2 units.

§ 96.283 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR SO_2 opt-in unit in § 96.280 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.286(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 96.222;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR SO_2 unit under § 96.204 and is not covered by a retired unit exemption under § 96.205 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Is not and, so long as the unit is a CAIR opt-in unit, will not become, an opt-in source under part 74 of this chapter;

(iv) Vents all of its emissions to a stack; and

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(v) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 96.222;

(3) A monitoring plan in accordance with subpart HHH of this part;

(4) A complete certificate of representation under § 96.213 consistent with § 96.282, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR SO_2 allowances under § 96.288(c) (subject to the conditions in §§ 96.284(h) and 96.286(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR SO_2 opt-in unit shall submit a complete CAIR permit application under § 96.222 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR SO_2 Trading Program in accordance with § 96.286 or the unit becomes a CAIR SO_2 unit under § 96.204, the CAIR SO_2 opt-in unit shall remain subject to the requirements for a CAIR SO_2 opt-in unit, even if the CAIR designated representative for the CAIR SO_2 opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.284 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.283 is submitted in accordance with the following:

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.283. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emissions rate and heat input of the unit are monitored and reported in accordance with subpart HHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the SO_2 emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HHH of this part and continuing until a CAIR opt-in permit is denied under § 96.284(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR SO_2 Trading Program in accordance with § 96.286.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR SO_2 Trading Program under § 96.284(g), during which period monitoring system availability must not be less than 90 percent under subpart HHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR SO_2 Trading Program under § 96.284(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's SO_2 emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section.

(d) *Baseline SO_2* emission rate. The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's SO_2 emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emissions rate (in lb/mmBtu) for such control period during which the unit has add-on SO_2 emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline SO_2 emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR SO_2 opt-in unit in § 96.280 and meets the elements certified in § 96.283(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR SO_2 opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR SO_2 opt-in unit in § 96.280 or meets the elements certified in § 96.283(a)(2), the permitting authority will issue a denial of a CAIR SO_2 opt-in permit for the unit.

(g) *Date of entry into CAIR SO_2 Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR SO_2 opt-in unit, and a CAIR SO_2 unit, as of the later of January 1, 2010

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or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR SO_2 opt-in unit. (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO_2 opt-in unit of CAIR SO_2 allowances under § 96.288(c) and such unit is repowered after its date of entry into the CAIR SO_2 Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR SO_2 opt-in unit replacing the original CAIR SO_2 opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline SO_2 emission rate as the original CAIR SO_2 opt-in unit, and the original CAIR SO_2 opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR SO_2 unit.

§ 96.285 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.222;

(2) The certification in § 96.283(a)(2);

(3) The unit's baseline heat input under § 96.284(c);

(4) The unit's baseline SO_2 emission rate under § 96.284(d);

(5) A statement whether the unit is to be allocated CAIR SO_2 allowances under § 96.288(c) (subject to the conditions in §§ 96.284(h) and 96.286(g));

(6) A statement that the unit may withdraw from the CAIR SO_2 Trading Program only in accordance with § 96.286; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.287.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.202 and, upon recordation by the Administrator under subpart FFF or GGG of this part or this subpart, every allocation, transfer, or deduction of CAIR SO_2 allowances to or from the compliance account of the source that includes a CAIR SO_2 opt-in unit covered by the CAIR opt-in permit.

§ 96.286 Withdrawal from CAIR SO_2 Trading Program.

Except as provided under paragraph (g) of this section, a CAIR SO_2 opt-in unit may withdraw from the CAIR SO_2 Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit of the acceptance of the withdrawal of the CAIR SO_2 opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR SO_2 Trading Program, the CAIR designated representative of the CAIR SO_2 opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR SO_2 Trading Program under § 96.284(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR SO_2 opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR SO_2 Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR SO_2 opt-in unit must meet the requirement to hold CAIR SO_2 allowances under § 96.206(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR SO_2 opt-in unit CAIR SO_2 allowances equal in number to and allocated for the same or a prior control period as any CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR SO_2 units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR SO_2 opt-in unit may submit a CAIR SO_2 allowance transfer for any remaining CAIR SO_2 allowances to another CAIR SO_2 Allowance Tracking System in accordance with subpart GGG of this part.

(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR SO_2 allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit of the acceptance of the withdrawal of the CAIR SO_2 opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit that the CAIR SO_2 opt-in unit's request to withdraw is denied. Such CAIR SO_2 opt-in unit shall continue to be a CAIR SO_2 opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR SO_2 opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR SO_2 opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR SO_2 Trading Program concerning any control periods for which the unit is a CAIR SO_2 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the CAIR SO_2 opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR SO_2 Trading Program. Once a CAIR SO_2 opt-in unit withdraws from the CAIR SO_2 Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.283 for such CAIR SO_2 opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under § 96.284.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR SO_2 opt-in unit shall not be eligible to withdraw from the CAIR SO_2 Trading Program if the CAIR designated representative of the CAIR SO_2 opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to the CAIR SO_2 opt-in unit of CAIR SO_2 allowances under § 96.288(c).

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§ 96.287 Change in regulatory status.

(a) *Notification.* If a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR SO_2 opt-in unit's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's actions.* (1) If a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, the permitting authority will revise the CAIR SO_2 opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.223 as of the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204.

(2)(i) The Administrator will deduct from the compliance account of the source that includes a CAIR SO_2 opt-in unit that becomes a CAIR SO_2 unit under § 96.204, CAIR SO_2 allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.288 for any control period after the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204; and

(B) If the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 is not December 31, the CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.288 for the control period that includes the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR SO_2 unit that becomes a CAIR SO_2 unit under § 96.204 contains the CAIR SO_2 allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, the CAIR SO_2 opt-in unit will be treated, solely for purposes of CAIR SO_2 allowance allocations under § 96.242, as a unit that commences operation on the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 and will be allocated CAIR SO_2 allowances under § 96.242.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 is not January 1, the following number of CAIR SO_2 allowances will be allocated to the CAIR SO_2 opt-in unit (as a CAIR SO_2 unit) under § 96.242 for the control period that includes the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204:

(A) The number of CAIR SO_2 allowances otherwise allocated to the CAIR SO_2 opt-in unit (as a CAIR SO_2 unit) under § 96.242 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.288 SO_2 allowance allocations to CAIR SO_2 opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.284(e), the permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period in which a CAIR opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR SO_2 opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR SO_2 allowance allocation will be the lesser of:

(i) The CAIR SO_2 opt-in unit's baseline heat input determined under § 96.284(c); or

(ii) The CAIR SO_2 opt-in unit's heat input, as determined in accordance with subpart HHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating CAIR SO_2 allowance allocations will be the lesser of:

(i) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period for which CAIR SO_2 allowances are to be allocated.

(3) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, and divided by 2,000 lb/ton.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO_2 opt-in unit of CAIR SO_2 allowances under this paragraph (subject to the conditions in §§ 96.284(h) and 96.286(g)), the permitting authority will allocate to the CAIR SO_2 opt-in unit as follows:

(1) For each control period in 2010 through 2014 for which the CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances,

(i) The heat input (in mmBtu) used for calculating CAIR SO_2 allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO_2 emission rate (in lb/mmBtu) used for calculating CAIR SO_2 allowance allocations will be the lesser of:

(A) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d); or

(B) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period in which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g).

(iii) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(1)(i) of this section, multiplied by the SO_2 emission rate

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under paragraph (c)(1)(ii) of this section, and divided by 2,000 lb/ton.

(2) For each control period in 2015 and thereafter for which the CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR SO_2 allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO_2 emission rate (in lb/mmBtu) used for calculating the CAIR SO_2 allowance allocation will be the lesser of:

(A) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d) multiplied by 10 percent; or

(B) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period for which CAIR SO_2 allowances are to be allocated.

(iii) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(2)(i) of this section, multiplied by the SO_2 emission rate under paragraph (c)(2)(ii) of this section, and divided by 2,000 lb/ton.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the CAIR SO_2 opt-in unit, the CAIR SO_2 allowances allocated by the permitting authority to the CAIR SO_2 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g), and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR SO_2 opt-in unit, the CAIR SO_2 allowances allocated by the permitting authority to the CAIR SO_2 opt-in unit under paragraph (a)(2) of this section.

■ 4. Part 96 is amended by adding subparts AAAA through CCCC, adding and reserving subpart DDDD and adding subparts EEEE through IIII to read as follows:

Subpart AAAA—CAIR NO_X Ozone Season Trading Program General Provisions

Subpart BBBB—CAIR Designated Representative for CAIR NO_X Ozone Season Sources

Subpart CCCC—Permits

Subpart DDDD—[Reserved]

Subpart EEEE—CAIR NO_X Ozone Season Allowance Allocations

Subpart FFFF—CAIR NO_X Ozone Season Allowance Tracking System

Subpart GGGG—CAIR NO_X Ozone Season Allowance Transfers

Subpart HHHH—Monitoring and Reporting

Subpart IIII—CAIR NO_X Ozone Season Opt-in Units

Subpart AAAA—CAIR NO_X Ozone Season Trading Program General Provisions

§ 96.301 Purpose.

This subpart and subparts BBBB through IIII establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBBB through IIII as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.123(aa)(1) or (2), of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.123(aa)(1) or (2), (bb), or (dd) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO_X Ozone Season Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.302 Definitions.

The terms used in this subpart and subparts BBBB through IIII shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO_X Ozone Season Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means, with regard to CAIR NO_X Ozone Season allowances issued under subpart EEEE, the determination by the permitting authority or the Administrator of the amount of such CAIR NO_X Ozone Season allowances to be initially credited to a CAIR NO_X Ozone Season unit or a new unit set-aside and, with regard to CAIR NO_X Ozone Season allowances issued under § 96.388 or § 51.123(aa)(2)(iii)(A) of this chapter, the determination by the permitting authority of the amount of such CAIR NO_X Ozone Season allowances to be initially credited to a CAIR NO_X Ozone Season unit.

Allowance transfer deadline means, for a control period, midnight of November 30, if it is a business day, or, if November 30 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR NO_X Ozone Season allowance transfer must be submitted for recordation in a CAIR NO_X Ozone Season source's compliance account in order to be used to meet the source's CAIR NO_X Ozone Season emissions limitation for such control period in accordance with § 96.354.

Alternate CAIR designated representative means, for a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BBBB and IIII of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR NO_X source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR SO_2 source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHHH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBBB and IIII of this part, to transfer and otherwise dispose of CAIR NO_X Ozone Season allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR NO_X source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR SO_2 source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X Ozone Season allowance means a limited authorization issued by the permitting authority under subpart EEEE of this part, § 96.388, or § 51.123(aa)(2)(iii)(A), (bb)(2)(iii) or (iv), or (dd)(3) or (4) of this chapter to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO_X Ozone Season Trading Program or a limited authorization issued by the permitting authority for a control period during 2003 through 2008 under the NO_X Budget Trading Program to emit one ton of nitrogen oxides during a control period, provided that the provision in § 51.121(b)(2)(i)(E) of this chapter shall not be used in applying this definition. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan that meet the requirements of § 51.121(p) of this chapter or § 51.123(aa)(1) or (2), (and (bb)(1)), (bb)(2), or (dd) of this chapter shall not be a CAIR NO_X Ozone Season allowance.

CAIR NO_X Ozone Season allowance deduction or *deduct CAIR NO_X Ozone Season allowances* means the permanent withdrawal of CAIR NO_X Ozone Season allowances by the Administrator from a compliance account in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO_X Ozone Season units at a CAIR NO_X Ozone Season source for a control period, determined in accordance with subpart HHHH of this part, or to account for excess emissions.

CAIR NO_X Ozone Season Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO_X Ozone Season allowances under the CAIR NO_X Ozone Season Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NO_X Ozone Season Allowance Tracking System account means an account in the CAIR NO_X Ozone Season Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO_X Ozone Season allowances.

CAIR NO_X Ozone Season allowances held or *hold CAIR NO_X Ozone Season allowances* means the CAIR NO_X Ozone Season allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFFF, GGGG, and IIII of this part, in a CAIR NO_X Ozone Season Allowance Tracking System account.

CAIR NO_X Ozone Season emissions limitation means, for a CAIR NO_X Ozone Season source, the tonnage equivalent of the CAIR NO_X Ozone Season allowances available for deduction for the source under § 96.354(a) and (b) for a control period.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and, except for purposes of § 96.305 and subpart EEEE of this part, a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCCC of this part, including any permit revisions, specifying the CAIR NO_X Ozone Season Trading Program requirements applicable to a CAIR NO_X Ozone Season source, to each CAIR NO_X Ozone Season unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:

(1) Except for purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(2) For purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.305.

(i) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.305, for a unit that is not a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.384(h) or § 96.387(b)(3), for a CAIR NO_X Ozone Season opt-in unit or

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a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.384(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.305.

(i) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.305, for a unit that is not a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1),(2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.384(h) or § 96.387(b)(3), for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.384(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NO_X Ozone Season Allowance Tracking System account, established by the Administrator for a CAIR NO_X Ozone Season source under subpart FFFF or IIII of this part, in which any CAIR NO_X Ozone Season allowance allocations for the CAIR NO_X Ozone Season units at the source are initially recorded and in which are held any CAIR NO_X Ozone Season allowances available for use for a control period in order to meet the source's CAIR NO_X Ozone Season emissions limitation in accordance with § 96.354.

Continuous emission monitoring system or *CEMS* means the equipment required under subpart HHHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HHHH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

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(6) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2 in percent O_2.

Control period or *ozone season* means the period beginning May 1 of a calendar year and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHHH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO_X Ozone Season units at a CAIR NO_X Ozone Season source during a control period that exceeds the CAIR NO_X Ozone Season emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO_X Ozone Season Allowance Tracking System account, established under subpart FFFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HHHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO_X emissions limitation means, with regard to a unit, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EEEE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year.

Operator means any person who operates, controls, or supervises a CAIR NO_X Ozone Season unit or a CAIR NO_X Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit;

(ii) Any holder of a leasehold interest in a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit; or

(iii) Any purchaser of power from a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO_X Ozone Season unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR NO_X Ozone Season allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO_X Ozone

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Season Trading Program in accordance with subpart CCCC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CAIR NO_X Ozone Season allowances, the movement of CAIR NO_X Ozone Season allowances by the Administrator into or between CAIR NO_X Ozone Season Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR NO_X Ozone Season allowance, the unique identification number assigned to each CAIR NO_X Ozone Season allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the States or the District of Columbia that adopts the CAIR NO_X Ozone Season Trading Program pursuant to § 51.123(aa)(1) or (2), (bb), or (dd) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NO_X Ozone Season emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.303 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
CO_2—carbon dioxide.
1NO_X—nitrogen oxides. hr—hour.
kW—kilowatt electrical. kWh—kilowatt hour. mmBtu—million Btu.
MWe—megawatt electrical. MWh—megawatt hour.
O_2—oxygen. ppm—parts per million. lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr-year.

§ 96.304 Applicability.

The following units in a State shall be CAIR NO_X Ozone Season units, and any

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source that includes one or more such units shall be a CAIR NO_X Ozone Season source, subject to the requirements of this subpart and subparts BBBB through HHHH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.305 Retired unit exemption.

(a)(1) Any CAIR NO_X Ozone Season unit that is permanently retired and is not a CAIR NO_X Ozone Season opt-in unit shall be exempt from the CAIR NO_X Ozone Season Trading Program, except for the provisions of this section, § 96.302, § 96.303, § 96.304, § 96.306(c)(4) through (8), § 96.307, and subparts EEEE through GGGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO_X Ozone Season unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CCCC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO_X Ozone Season allowances under subpart EEEE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NO_X Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.322 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.306 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.322 in accordance with the deadlines specified in § 96.321(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart IIII of this part, the owners and operators of a CAIR NO_X Ozone Season source that is not otherwise required to have a title V operating permit and each CAIR NO_X Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of this part for such CAIR NO_X Ozone Season source and such CAIR NO_X Ozone Season unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NO_X Ozone Season source with the CAIR NO_X Ozone Season emissions

limitation under paragraph (c) of this section.

(c) *Nitrogen oxides ozone season emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under § 96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under § 96.370(b)(1), (2), (3), or (7).

(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.

(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subpart EEEE of this part.

(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X Ozone Season unit.

(d) *Excess emissions requirements.* (1) If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:

(i) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under § 96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.

(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under subpart HHHH of this part.

(f) *Liability.* (1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.

(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.

(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.307 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO_X Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.308 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO_X Ozone Season Trading Program are set forth in part 78 of this chapter.

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Subpart BBBB—CAIR Designated Representative for CAIR NO_X Ozone Season Sources

§ 96.310 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.311, each CAIR NO_X Ozone Season source, including all CAIR NO_X Ozone Season units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO_X Ozone Season Trading Program concerning the source or any CAIR NO_X Ozone Season unit at the source.

(b) The CAIR designated representative of the CAIR NO_X Ozone Season source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 96.313(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.313, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO_X Ozone Season source represented and each CAIR NO_X Ozone Season unit at the source in all matters pertaining to the CAIR NO_X Ozone Season Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO_X Ozone Season Allowance Tracking System account will be established for a CAIR NO_X Ozone Season unit at a source, until the Administrator has received a complete certificate of representation under § 96.313 for a CAIR designated representative of the source and the CAIR NO_X Ozone Season units at the source.

(e)(1) Each submission under the CAIR NO_X Ozone Season Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO_X Ozone Season source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.311 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.313 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.313, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.302, 96.310(a) and (d), 96.312, 96.313, 96.351, and 96.382 whenever the term ''CAIR designated representative'' is used in subparts AAAA through IIII of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.312 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source.

(c) Changes in owners and operators. (1) In the event a new owner or operator of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit is not included in the list of owners and operators in the certificate of representation under § 96.313, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.313 amending the list of owners and operators to include the change.

§ 96.313 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include

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the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NO_X Ozone Season source, and each CAIR NO_X Ozone Season unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO_X Ozone Season source and of each CAIR NO_X Ozone Season unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO_X Ozone Season unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Ozone Season Trading Program on behalf of the owners and operators of the source and of each CAIR NO_X Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR NO_X Ozone Season unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_X Ozone Season unit, or where a customer purchases power from a CAIR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO_X Ozone Season unit at the source; and CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X Ozone Season allowances by contract, CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.314 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.313 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.313 is received by the Administrator.

(b) Except as provided in § 96.312(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NO_X Ozone Season Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR NO_X Ozone Season allowance transfers.

Subpart CCCC—Permits

§ 96.320 General CAIR NO_X Ozone Season Trading Program permit requirements.

(a) For each CAIR NO_X Ozone Season source required to have a title V operating permit or required, under subpart IIII of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart IIII of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source covered by the CAIR permit, all applicable CAIR NO_X Ozone Season Trading Program, CAIR NO_X Annual Trading Program, and CAIR SO_2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.321 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR NO_X Ozone Season source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.322 for the source covering each CAIR NO_X Ozone Season unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO_X Ozone Season unit commences operation.

(b) *Duty to Reapply.* For a CAIR NO_X Ozone Season source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 96.322 for the source covering each CAIR NO_X Ozone Season unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.322 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NO_X Ozone Season source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR NO_X Ozone Season source;

(b) Identification of each CAIR NO_X Ozone Season unit at the CAIR NO_X Ozone Season source; and

(c) The standard requirements under § 96.306.

§ 96.323 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.322.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.302 and, upon recordation by the Administrator under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from the compliance account of the CAIR NO_X Ozone Season source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO_X Ozone Season source's title V operating permit or other federally enforceable permit as applicable.

§ 96.324 CAIR permit revisions.

Except as provided in § 96.323(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDDD—[Reserved]

Subpart EEEE—CAIR NO_X Ozone Season Allowance Allocations

§ 96.340 State trading budgets.

(a) Except as provided in paragraph (b) of this section, the State trading budgets for annual allocations of CAIR NO_X Ozone Season allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Alabama	32,182	26,818
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989

(b) If a permitting authority issues additional CAIR NO_X Ozone Season allowance allocations under § 51.123(aa)(2)(iii)(A) of this chapter, the amount in the State trading budget for a control period in a calendar year will be the sum of the amount set forth for the State and for the year in paragraph (a) of this section and the amount of additional CAIR NO_X Ozone Season allowance allocations issued under § 51.123(aa)(2)(iii)(A) of this chapter for the year.

§ 96.341 Timing requirements for CAIR NO_X Ozone Season allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X Ozone Season allowance allocations in accordance with paragraph (b)(1), the Administrator will assume that the allocations of CAIR NO_X Ozone Season allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period.

(c)(1) By July 31, 2009 and July 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(c), (a), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X Ozone Season allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X Ozone Season allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period and except that any CAIR NO_X Ozone Season unit that would otherwise be allocated CAIR NO_X Ozone Season allowances under § 96.342(a) and (b), as well as under § 96.342(a), (c), and (d), for the applicable control period will be assumed to be allocated no CAIR NO_X Ozone Season allowances under § 96.342(a), (c), and (d) for the applicable control period.

§ 96.342 CAIR NO_X Ozone Season allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO_X Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NO_X Ozone Season unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit's control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit's control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input, and a unit's status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NO_X emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,414 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO_X Ozone Season units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO_X Ozone Season allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO_X emissions in the State trading budget under § 96.340 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NO_X Ozone Season allowances to each CAIR NO_X Ozone Season unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO_X Ozone Season allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO_X Ozone Season unit to the total amount of baseline heat input of all such CAIR NO_X Ozone Season units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NO_X Ozone Season allowances to CAIR NO_X Ozone Season units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO_X Ozone Season allowances equal to 5 percent for a control period in 2009 through 2013, and 3 percent for a control period in 2014 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.340.

(2) The CAIR designated representative of such a CAIR NO_X Ozone Season unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NO_X Ozone Season allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO_X Ozone Season unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO_X Ozone Season allowances under paragraph (b) of this section. The CAIR NO_X Ozone Season allowance allocation request must be submitted on or before April 1 before the first control period for which the CAIR NO_X Ozone Season allowances are requested and after the date on which the CAIR NO_X Ozone Season unit commences commercial operation.

(3) In a CAIR NO_X Ozone Season allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO_X Ozone Season allowances in an amount not exceeding the CAIR NO_X Ozone Season unit's total tons of NO_X emissions during the control period immediately before such control period.

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(4) The permitting authority will review each CAIR NO_X Ozone Season allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NO_X Ozone Season allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after April 1 before the control period, the permitting authority will determine the sum of the CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NO_X Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each CAIR NO_X Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NO_X Ozone Season allowances (if any) allocated for the control period to the CAIR NO_X Ozone Season unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NO_X Ozone Season allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NO_X Ozone Season unit that was allocated CAIR NO_X Ozone Season allowances under paragraph (b) of this section an amount of CAIR NO_X Ozone Season allowances equal to the total amount of such remaining unallocated CAIR NO_X Ozone Season allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.340, and rounded to the nearest whole allowance as appropriate.

Subpart FFFF—CAIR NO_X Ozone Season Allowance Tracking System

§ 96.350 [Reserved]

§ 96.351 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.384(e), upon receipt of a complete certificate of representation under § 96.313, the Administrator will establish a compliance account for the CAIR NO_X Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) General accounts—(1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO_X Ozone Season allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account in all matters pertaining to the CAIR NO_X Ozone Season Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall

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be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR NO_X Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO_X Ozone Season allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO_X Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NO_X Ozone Season allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.352 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO_X Ozone Season Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO_X Ozone Season allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.353 Recordation of CAIR NO_X Ozone Season allowance allocations.

(a) By December 1, 2006, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at a source, as submitted by the permitting authority in accordance with § 96.341(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or as determined by the Administrator in

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accordance with § 96.341(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a CAIR NO_X Ozone Season source's compliance account under § 96.354, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.341(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By September 1, 2009 and September 1 of each year thereafter, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.341(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated CAIR NO_X Ozone Season allowances.* When recording the allocation of CAIR NO_X Ozone Season allowances for a CAIR NO_X Ozone Season unit in a compliance account, the Administrator will assign each CAIR NO_X Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO_X Ozone Season allowance is allocated.

§ 96.354 Compliance with CAIR NO_X emissions limitation.

(a) *Allowance transfer deadline.* The CAIR NO_X Ozone Season allowances are available to be deducted for compliance with a source's CAIR NO_X Ozone Season emissions limitation for a control period in a given calendar year only if the CAIR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO_X Ozone Season allowance transfer correctly submitted for recordation under § 96.360 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.361, of CAIR NO_X Ozone Season allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NO_X Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NO_X Ozone Season emissions limitation for the control period, as follows:

(1) Until the amount of CAIR NO_X Ozone Season allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HHHH of this part, from all CAIR NO_X Ozone Season units at the source for the control period; or

(2) If there are insufficient CAIR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CAIR NO_X Ozone Season allowances by serial number.* The CAIR authorized account representative for a source's compliance account may request that specific CAIR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO_X Ozone Season source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR NO_X Ozone Season allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR NO_X Ozone Season allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NO_X Ozone Season allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NO_X Ozone Season allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to subpart GGGG of this part, in the order of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NO_X Ozone Season source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CAIR NO_X Ozone Season allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NO_X Ozone Season source or the CAIR NO_X Ozone Season units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NO_X Ozone Season Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NO_X Ozone Season allowances from or transfer CAIR NO_X Ozone Season allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.355 Banking.

(a) CAIR NO_X Ozone Season allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR NO_X Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NO_X Ozone Season allowance is deducted or transferred under § 96.354, § 96.356, or subpart GG of this part.

§ 96.356 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO_X Ozone Season Allowance Tracking System account. Within 10 business

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days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.357 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.360 for any CAIR NO_X Ozone Season allowances in the account to one or more other CAIR NO_X Ozone Season Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO_X Ozone Season allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO_X Ozone Season allowances into the account under § 96.360 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGGG—CAIR NO_X Ozone Season Allowance Transfers

§ 96.360 Submission of CAIR NO_X Ozone Season allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO_X Ozone Season allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO_X Ozone Season allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO_X Ozone Season allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.361 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO_X Ozone Season allowance transfer, the Administrator will record a CAIR NO_X Ozone Season allowance transfer by moving each CAIR NO_X Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.360; and

(2) The transferor account includes each CAIR NO_X Ozone Season allowance identified by serial number in the transfer.

(b) A CAIR NO_X Ozone Season allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO_X Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.354 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO_X Ozone Season allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.362 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR NO_X Ozone Season allowance transfer under § 96.361, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR NO_X Ozone Season allowance transfer that fails to meet the requirements of § 96.361(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO_X Ozone Season allowance transfer for recordation following notification of non-recordation.

Subpart HHHH—Monitoring and Reporting

§ 96.370 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO_X Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.302 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR NO_X Ozone Season unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.302. The owner or operator of a unit that is not a CAIR NO_X Ozone Season unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO_X Ozone Season unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR NO_X Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 96.371 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO_X Ozone Season unit that commences commercial operation before July 1, 2007, by May 1, 2008.

(2) For the owner or operator of a CAIR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2007 and that reports on an annual basis under § 96.374(d), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) May 1, 2008, if the compliance date under paragraph (b)(2)(i) is before May 1, 2008.

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(3) For the owner or operator of a CAIR NO_X Ozone Season unit that commences operation on or after July 1, 2007 and that reports on a control period basis under § 96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a CAIR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (6), or (7) of this section and that reports on an annual basis under § 96.374(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(5) For the owner or operator of a CAIR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (3), (6), or (7) of this section and that reports on a control period basis under § 96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a unit for which a CAIR NO_X Ozone Season opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, by the date specified in § 96.384(b).

(7) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section and solely for purposes of § 96.306(c)(2), for the owner or operator of a CAIR NO_X Ozone Season opt-in unit, by the date on which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program as provided in § 96.384(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR NO_X Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b)(4) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in § 75.74(c)(7) of this chapter or subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(4) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR NO_X Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.375.

(2) No owner or operator of a CAIR NO_X Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NO_X Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NO_X Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.305 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.371(d)(3)(i).

§ 96.371 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO_X Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.370(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.370(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12, § 75.17, or subpart H of part 75 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.375(a) to determine whether the approval applies

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under the CAIR NO_X Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO_X Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 96.370(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.370(a)(1)(including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.370(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 96.370(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 96.370(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.370(a)(1). For recertifications, replace the words "certification" and "initial certification" with the word "recertification", replace the word "certified" with the word "recertified," and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.373.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO_X Ozone Season Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) Certification application approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NO_X Ozone Season Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a

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CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.372(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.*, NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's or the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) *Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter.* The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) *Certification/recertification procedures for alternative monitoring systems.* The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.372 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.371 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.371 for each disapproved monitoring system.

§ 96.373 Notifications.

The CAIR designated representative for a CAIR NO_X Ozone Season unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 96.374 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 96.310(e)(1).

(b) *Monitoring plans.* The owner or operator of a CAIR NO_X Ozone Season unit shall comply with requirements of § 75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, §§ 96.383 and 96.384(a).

(c) *Certification applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.371, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) If the CAIR NO_X Ozone Season unit is subject to an Acid Rain emissions limitation or a CAIR NO_X emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the CAIR designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for

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such unit for the entire year and shall report the NO_X mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008; or

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.370(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering May 1, 2008 through June 30, 2008.

(2) If the CAIR NO_X Ozone Season unit is not subject to an Acid Rain emissions limitation or a CAIR NO_X emissions limitation, then the CAIR designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in § 75.74(c) of this chapter) and report NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008;

(B) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.370(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For CAIR NO_X Ozone Season units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program or CAIR SO_2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 96.375 Petitions.

(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO_X Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO_X Ozone Season unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO_X Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional continuous emission monitoring system required under § 75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.376 Additional requirements to provide heat input data.

The owner or operator of a CAIR NO_X Ozone Season unit that monitors and reports NO_X mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart IIII—CAIR NO_X Ozone Season Opt-in Units

§ 96.380 Applicability.

A CAIR NO_X Ozone Season opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR NO_X Ozone Season unit under § 96.304 and is not covered by a retired unit exemption under § 96.305 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHHH of this part.

§ 96.381 General.

(a) Except as otherwise provided in §§ 96.301 through 96.304, §§ 96.306

through 96.308, and subparts BBBB and CCCC and subparts FFFF through HHHH of this part, a CAIR NO_X Ozone Season opt-in unit shall be treated as a CAIR NO_X Ozone Season unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO_X Ozone Season unit before issuance of a CAIR opt-in permit for such unit.

§ 96.382 CAIR designated representative.

Any CAIR NO_X Ozone Season opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO_X Ozone Season units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO_X Ozone Season units.

§ 96.383 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.386 (f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under §96.322;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR NO_X Ozone Season unit under § 96.304 and is not covered by a retired unit exemption under § 96.305 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §96.322;

(3) A monitoring plan in accordance with subpart HHHH of this part;

(4) A complete certificate of representation under § 96.313 consistent with § 96.382, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO_X Ozone Season allowances under § 96.388(c) (subject to the conditions in §§ 96.384(h) and 96.386(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR NO_X Ozone Season opt-in unit shall submit a complete CAIR permit application under § 96.322 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or the permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR NO_X Annual Trading Program in accordance with § 96.186 or the unit becomes a CAIR NO_X unit under § 96.304, the CAIR NO_X opt-in unit shall remain subject to the requirements for a CAIR NO_X opt-in unit, even if the CAIR designated representative for the CAIR NO_X opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.384 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.383 is submitted in accordance with the following:

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.383. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO_X emissions rate and the heat input of the unit emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHHH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HHHH of this part and continuing until a CAIR opt-in permit is denied under § 96.384(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO_X Ozone Season Trading Program in accordance with § 96.386.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), during which period monitoring system availability must not be less than 90 percent under subpart HHHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section.

(d) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's NO_X emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's NO_X emissions rate and heat input are monitored and

reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for such control period during which the unit has add-on NO_X emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 and meets the elements certified in § 96.383(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO_X Ozone Season opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 or meets the elements certified in § 96.383(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) *Date of entry into CAIR NO_X Ozone Season Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NO_X Ozone Season opt-in unit, and a CAIR NO_X Ozone Season unit, as of the later of May 1, 2009 or May 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR NO_X Ozone Season opt-in unit. (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under § 96.388(c) and such unit is repowered after its date of entry into the CAIR NO_X Ozone Season Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO_X Ozone Season opt-in unit replacing the original CAIR NO_X Ozone Season opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO_X emission rate as the original CAIR NO_X Ozone Season opt-in unit, and the original CAIR NO_X Ozone Season opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR NO_X Ozone Season unit.

§ 96.385 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.322;

(2) The certification in § 96.383(a)(2);

(3) The unit's baseline heat input under § 96.384(c);

(4) The unit's baseline NO_X emission rate under § 96.384(d);

(5) A statement whether the unit is to be allocated CAIR NO_X Ozone Season allowances under § 96.388(c) (subject to the conditions in §§ 96.384(h) and 96.386(g));

(6) A statement that the unit may withdraw from the CAIR NO_X Ozone Season Trading Program only in accordance with § 96.386; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.387.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.302 and, upon recordation by the Administrator under subpart FFFF or GGGG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO_X Ozone Season allowances to or from the compliance account of the source that includes a CAIR NO_X Ozone Season opt-in unit covered by the CAIR opt-in permit.

§ 96.386 Withdrawal from CAIR NO_X Ozone Season Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO_X Ozone Season opt-in unit may withdraw from the CAIR NO_X Ozone Season Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO_X Ozone Season opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR NO_X Ozone Season Trading Program, the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of entry into the CAIR NO_X Ozone Season Trading Program under § 96.384(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR NO_X Ozone Season opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO_X Ozone Season Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO_X Ozone Season opt-in unit must meet the requirement to hold CAIR NO_X Ozone Season allowances under § 96.306(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit CAIR NO_X Ozone Season allowances equal in number to and allocated for the same or a prior control period as any CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO_X Ozone Season units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NO_X Ozone Season opt-in unit may submit a CAIR NO_X Ozone Season allowance transfer for any remaining CAIR NO_X Ozone Season allowances to another CAIR NO_X Ozone Season Allowance Tracking System in accordance with subpart GGGG of this part.

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(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO_X Ozone Season allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO_X Ozone Season opt-in unit as of midnight on September 30 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit that the CAIR NO_X Ozone Season opt-in unit's request to withdraw is denied. Such CAIR NO_X opt-in unit shall continue to be a CAIR NO_X Ozone Season opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO_X Ozone Season opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO_X Ozone Season opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO_X Ozone Season Trading Program concerning any control periods for which the unit is a CAIR NO_X Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR NO_X Ozone Season opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) *Ability to reapply to the CAIR NO_X Ozone Season Trading Program.* Once a CAIR NO_X Ozone Season opt-in unit withdraws from the CAIR NO_X Ozone Season Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.383 for such CAIR NO_X Ozone Season opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under § 96.384.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO_X Ozone Season opt-in unit shall not be eligible to withdraw from the CAIR NO_X Ozone Season Trading Program if the CAIR designated representative of the CAIR NO_X opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to the CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under § 96.388(c).

§ 96.387 Change in regulatory status.

(a) *Notification.* If a CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO_X Ozone Season opt-in unit's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's actions.* (1) If a CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, the permitting authority will revise the CAIR NO_X Ozone Season opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.323 as of the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit that becomes a CAIR NO_X Ozone Season unit under § 96.304, CAIR NO_X Ozone Season allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for any control period after the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304; and

(B) If the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 is not September 30, the CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for the control period that includes the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO_X Ozone Season unit that becomes a CAIR NO_X Ozone Season unit under § 96.304 contains the CAIR NO_X Ozone Season allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, the CAIR NO_X Ozone Season opt-in unit will be treated, solely for purposes of CAIR NO_X Ozone Season allowance allocations under § 96.342, as a unit that commences operation on the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 and will be allocated CAIR NO_X Ozone Season allowances under § 96.342.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 is not May 1, the following number of CAIR NO_X Ozone Season allowances will be allocated to the CAIR NO_X Ozone Season opt-in unit (as a CAIR NO_X Ozone Season unit) under § 96.342 for the control period that includes the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304:

(A) The number of CAIR NO_X Ozone Season allowances otherwise allocated to the CAIR NO_X Ozone Season opt-in unit (as a CAIR NO_X Ozone Season unit) under § 96.342 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.388 NO_X allowance allocations to CAIR NO_X Ozone Season opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.384(e), the permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO_X Ozone Season opt-in unit enters the

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CAIR NO_X Ozone Season Trading Program under § 96.384(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than July 31 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g) and July 31 of each year thereafter, the permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO_X opt-in unit, in accordance with paragraph (b)or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocation will be the lesser of:

(i) The CAIR NO_X Ozone Season opt-in unit's baseline heat input determined under § 96.384(c); or

(ii) The CAIR NO_X Ozone Season opt-in unit's heat input, as determined in accordance with subpart HHHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be the lesser of:

(i) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period for which CAIR NO_X Ozone Season allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under this paragraph (subject to the conditions in §§ 96.384(h) and 96.386(g)), the permitting authority will allocate to the CAIR NO_X Ozone Season opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be the lesser of:

(A) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d); or

(B) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period in which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g).

(iii) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d); or

(C) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period for which CAIR NO_X Ozone Season allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit, the CAIR NO_X Ozone Season allowances allocated by the permitting authority to the CAIR NO_X Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1, of the control period in which a CAIR opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit, the CAIR NO_X Ozone Season allowances allocated by the permitting authority to the CAIR NO_X Ozone Season opt-in unit under paragraph (a)(2) of this section.

[FR Doc. 05–5723 Filed 5–11–05; 8:45 am]
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contains copyrighted material, Confidential Business Information (''CBI''), or other information whose disclosure is restricted by statute. Information claimed as CBI and other information whose disclosure is restricted by statute is not included in the official public docket or in the electronic public docket. EPA's policy is that copyrighted material, including copyrighted material contained in a public comment, will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

B. How and to whom do I submit comments?

You may submit comments as provided in the **ADDRESSES** section. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' EPA is not required to consider these late comments.

If you submit an electronic comment, EPA recommends that you include your name, mailing address, and an email address or other contact information in the body of your comment and with any disk or CD ROM you submit. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. Any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Use of the *www.regulations.gov* Web site to submit comments to EPA electronically is EPA's preferred method for receiving comments. The electronic public docket system is an ''anonymous access'' system, which means EPA will not know your identity, email address, or other contact information unless you provide it in the body of your comment. In contrast to EPA's electronic public docket, EPA's electronic mail (email) system is not an ''anonymous access'' system. If you send an email comment directly to the Docket without going through *www.regulations.gov,* your email address is automatically captured and included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

Dated: December 23, 2016.

Gautam Srinivasan,

Acting Associate General Counsel.

[FR Doc. 2017–00056 Filed 1–5–17; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–9031–2]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–7146 or *http://www.epa.gov/nepa.*

Weekly receipt of Environmental Impact Statements (EISs)

Filed 12/26/2016 Through 12/30/2016

Pursuant to 40 CFR 1506.9.

Notice: Section 309(a) of the Clean Air Act requires that EPA make public its comments on EISs issued by other Federal agencies. EPA's comment letters on EISs are available at: *http://www.epa.gov/compliance/nepa/eisdata.html.*

EIS No. 20160319, Draft, BLM, CA, Central Coast Field Office Draft Resource Management Plan Amendment for the Oil and Gas Leasing and Development, Comment Period Ends: 02/21/2017, Contact: Melinda Moffitt 916–978–4376

EIS No. 20160320, Final, USFS, OR, Magone Project, Review Period Ends: 02/13/2017, Contact: Sasha Fertig 541–575–3061

EIS No. 20160321, Draft Supplement, FTA, CA, BART Silicon Valley Phase II Extension Project, Comment Period Ends: 02/20/2017, Contact: Mary Nguyen 213–202–3960

EIS No. 20160322, Final, FRA, AZ, Arizona Passenger Rail Corridor: Tucson to Phoenix, Review Period Ends: 03/10/2017, Contact: Andrea Martin 202–493–6201

EIS No. 20160323, Draft, NOAA, WI, Wisconsin—Lake Michigan National Marine Sanctuary, Comment Period Ends: 03/31/2017, Contact: Russ Green 920–459–4425

EIS No. 20160324, Draft, NOAA, MD, Mallows Bay—Potomac River National Marine Sanctuary Designation, Comment Period Ends: 03/31/2017, Contact: Paul Orlando 240–460–1978

EIS No. 20160325, Draft, FERC, VA, Atlantic Coast Pipeline and Supply Header Project, Comment Period Ends: 04/06/2017, Contact: Kevin Bowman 202–502–6287

EIS No. 20160326, Final, FERC, PA, Atlantic Sunrise Project, Review Period Ends: 02/06/2017, Contact: Joanne Wachholder 202–502–8056

EIS No. 20160327, Final Supplement, USN, CA, Land Acquisition and Airspace Establishment to Support Large-Scale Marine Air Ground Task Force Live-Fire Training Marine Corps Combat Center Twentynine Palms, Review Period Ends: 02/06/2017, Contact: Jesse Martinez 619–532–3844

EIS No. 20160328, Draft Supplement, USACE, LA, Mississippi River, Baton Rouge to the Gulf of Mexico Mississippi River-Gulf Outlet, Louisiana, New Industrial Canal Lock and Connecting Channels Project, Comment Period Ends: 02/20/2017, Contact: Mark Lahare 504–862–1344

Dated: January 3, 2017.

Dawn Roberts,

Management Analyst, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2017–00055 Filed 1–5–17; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2016–0751; FRL–9958–02–OAR]

Notice of Availability of the Environmental Protection Agency's Preliminary Interstate Ozone Transport Modeling Data for the 2015 Ozone National Ambient Air Quality Standard (NAAQS)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of data availability (NODA); request for public comment.

SUMMARY: The Environmental Protection Agency (EPA) is providing notice that preliminary interstate ozone transport modeling data and associated methods relative to the 2015 ozone National Ambient Air Quality Standard (NAAQS) are available for public review and comment. This information is being provided to help states develop State Implementation Plans (SIPs) to address the requirements of Clean Air Act (CAA) section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The information available includes: (1) Emission inventories for 2011 and 2023, supporting data used to develop those emission inventories, methods and data used to process emission inventories into a form that can be used for air quality modeling; and (2) air quality

modeling results for 2011 and 2023, base period (*i.e.,* 2009–2013) average and maximum ozone design value concentrations, projected 2023 average and maximum ozone design value concentrations, and projected 2023 ozone contributions from state-specific anthropogenic emissions and other contribution categories to ozone concentrations at individual ozone monitoring sites.

A docket has been established to facilitate public review of the data and to track comments.

DATES: Comments must be received on or before 90 days after publication in the **Federal Register**.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2016–0751, to the *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, Cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

When submitting comments, remember to:

1. Identify the notice by docket number and other identifying information (subject heading, **Federal Register** date and page number).

2. Explain your comments, why you agree or disagree; suggest alternatives and substitute data that reflect your requested changes.

3. Describe any assumptions and provide any technical information and/or data that you used.

4. Provide specific examples to illustrate your concerns, and suggest alternatives.

5. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

6. Make sure to submit your comments by the comment period deadline identified.

For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available (*e.g.,* CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions on the emissions data and on how to submit comments on the emissions-related projection methodologies, contact Alison Eyth, Air Quality Assessment Division, Environmental Protection Agency, Mail code: C339–02, 109 T.W. Alexander Drive, Research Triangle Park, NC 27709; telephone number: (919) 541–2478; fax number: (919) 541–1903; email: *eyth.alison@epa.gov.* For questions on the preliminary air quality modeling and ozone contributions and how to submit comments on the air quality modeling data and related methodologies, contact Norm Possiel, Air Quality Assessment Division, Environmental Protection Agency, Mail code: C439–01, 109 T.W. Alexander Drive, Research Triangle Park, NC 27709; telephone number: (919) 541–5692; fax number: (919) 541–0044; email: *possiel.norm@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On October 26, 2015 (80 FR 65292), the EPA published a rule revising the 8-hour ozone NAAQS from 0.075 parts per million (ppm) to a new, more protective level of 0.070 ppm. Section 110(a)(1) of the CAA requires states to submit SIPs that provide for the implementation, maintenance, and enforcement of a NAAQS within 3 years of the promulgation of a new or revised standard. Such plans are required to address the applicable requirements of CAA section 110(a)(2) and are generally referred to as ''infrastructure'' SIPs. Among the requirements in CAA section 110(a)(2) that must be addressed in these plans is the ''Good Neighbor'' provision, section 110(a)(2)(D)(i)(I), which requires states to develop SIPs that prohibit any source or other emissions activity within the state from emitting air pollutants in amounts that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in another state. With respect to the 2015 ozone NAAQS, the Good Neighbor SIPs are due within 3 years of promulgation of the revised NAAQS, or by October 26, 2018.

On October 1, 2015, when EPA Administrator McCarthy signed the ozone NAAQS revision, the agency also issued a memorandum [1] to EPA Regional Administrators communicating a process for delivering the protections afforded by the revised NAAQS, including implementing CAA requirements like the Good Neighbor provision. In that memorandum, the EPA emphasized that we will be working with state, local, federal and tribal partners to carry out the duties of ozone air quality management in a manner that maximizes common sense, flexibility and cost-effectiveness while achieving improved public health expeditiously and abiding by the legal requirements of the CAA.

The memorandum noted that the EPA believes that the Good Neighbor provision for the 2015 ozone NAAQS can be addressed in a timely fashion using the framework of the Cross-State Air Pollution Rule (CSAPR), especially given the court decisions upholding important elements of that framework.[2] The EPA also expressed its intent to issue timely information concerning interstate ozone transport for the 2015 ozone NAAQS as a first step to help

[1] Memorandum from Janet McCabe, Acting Assistant administrator, Office of Air and Radiation to Regional Administrators, Regions 1–10, ''Implementing the 2015 Ozone National Ambient Air Quality Standards,'' available at *https://www.epa.gov/sites/production/files/2015-10/documents/implementation_memo.pdf.*

[2] *See EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584, 1607 (2014) (holding the EPA's use of uniform oxides of nitrogen (NO_X) stringency to apportion emission reduction responsibilities among upwind states ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address''); *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 135–36 (D.C. Cir. 2015) (affirming EPA's use of air quality modeling to project future nonattainment and maintenance receptors and to calculate emissions budgets, and holding that the EPA affords independent effect to the ''interfere with maintenance'' prong of the Good Neighbor provision in identifying maintenance receptors).

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facilitate the development of SIPs addressing the Good Neighbor provision. The EPA recognizes that the CAA provides that states have the primary responsibility to submit timely SIPs, as well as the EPA's own backstop role to develop and promulgate Federal Implementation Plans (FIPs), as appropriate.

This notice includes preliminary air quality modeling data that will help states as they develop SIPs to address the cross-state transport of air pollution under the CAA's Good Neighbor provision as it pertains to the 2015 ozone NAAQS. These data are considered preliminary because states may choose to modify or supplement these data in developing their Good Neighbor SIPs and/or EPA may update these data for the purpose of potential future analyses or regulatory actions related to interstate ozone transport for the 2015 ozone NAAQS.

The EPA has applied what it refers to as the CSAPR framework to address the requirements of the Good Neighbor provision for regional pollutants like ozone. This framework involves a 4-step process: (1) Identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards (*i.e.,* NAAQS); (2) determining which upwind states contribute to these problems in amounts sufficient to ''link'' them to the downwind air quality problems; (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS by quantifying upwind reductions in ozone precursor emissions and apportioning emission reduction responsibility among upwind states; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance or the NAAQS downwind, adopting SIPs or FIPs that eliminate such emissions. The EPA applied this framework in the original CSAPR rulemaking (76 FR 48208) to address the Good Neighbor provision for the 1997 ozone NAAQS and the 1997 and 2006 fine particulate matter ($PM_{2.5}$) NAAQS. On October 26, 2016 (81 FR 74504), the EPA again applied this framework in an update to CSAPR (referred to as the CSAPR Update) to address the Good Neighbor provision for the 2008 ozone NAAQS. This notice provides information regarding steps 1 and 2 of the CSAPR framework for purposes of evaluating interstate transport with respect to the 2015 ozone NAAQS. This preliminary modeling to quantify contributions for the year 2023 is intended to help inform state efforts to address interstate transport with respect to the 2015 ozone NAAQS.

The year 2023 was used as the analytic year for this preliminary modeling because that year aligns with the expected attainment year for Moderate ozone nonattainment areas, given that the CAA requires the EPA to finalize area designations for the 2015 ozone NAAQS in October 2017.[3] *See North Carolina* v. *EPA,* 531 F.3d 896, 911–12 (D.C. Cir. 2008), *modified on reh'g,* 550 F.3d 1176 (holding the Good Neighbor provision requires implementation of emissions reductions be harmonized with the applicable downwind attainment dates).

As noted above, this notice meets the EPA's stated intention in the October 2015 memorandum to provide information relevant to the Good Neighbor provision for the 2015 ozone NAAQS. Specifically, this notice evaluates states' contributions to downwind ozone problems relative to the screening threshold—equivalent to 1 percent of the NAAQS—that the CSAPR framework uses to identify states ''linked'' to downwind air quality problems for further consideration to address interstate ozone transport. The EPA believes that states will find this information useful in their development of Good Neighbor SIPs for the 2015 ozone NAAQS, and we seek their comments on it.[4] The EPA believes that states may rely on this or other appropriate modeling, data or analyses to develop approvable Good Neighbor SIPs which, as noted previously, are due on October 26, 2018. States that act now to address their planning obligation pursuant to the Good Neighbor provision would benefit from improved ozone air quality both within the state and with respect to other states.

This notice provides an opportunity for review and comment on the agency's preliminary ozone transport modeling data relevant for the 2015 ozone NAAQS.

II. Air Quality Modeling and Related Data and Methodologies

A. Base Year and Future Base Case Emissions

For this transport assessment, the EPA used a 2011-based modeling platform to develop base year and future year emissions inventories for input to air quality modeling. This platform included meteorology for 2011, base year emissions for 2011, and future year base case emissions for 2023. The 2011 and 2023 air quality modeling results were used to identify areas that are projected to be nonattainment or have problems maintaining the 2015 ozone NAAQS in 2023. Ozone source apportionment modeling for 2023 was used to quantify contributions from emissions in each state to ozone concentrations at each of the projected nonattainment and maintenance receptors in that future year.[5]

The 2011 and 2023 emissions data and the state and federal rules included in the 2023 base case are described in detail in the documents, ''Preparation of Emissions Inventories for the Version 6.3 2011 Emissions Modeling Platform''; ''Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023''; and ''EPA Base Case v.5.16 for 2023 Ozone Transport NODA Using IPM Incremental Documentation''; all of which are available in the docket for this notice.

In brief, the 2011 base year emissions and projection methodologies used here to create emissions for 2023 are similar to what was used in the final CSAPR Update. The key differences between the 2011 inventories used for the final CSAPR Update and the 2011 inventories used for the 2015 ozone NAAQS preliminary interstate transport modeling include updates to mobile source and electric generating unit (EGU) emissions, the inclusion of fire emissions in Canada and Mexico, and updated estimates of anthropogenic emissions for Mexico. The key differences in methodologies for projecting non-EGU sector emissions (*e.g.,* onroad and nonroad mobile, oil

[3] *See* 42 U.S.C. 7407(d)(1)(B) (requiring the EPA to finalize designations no later than 2 years after promulgation of a new or revised NAAQS). On November 17, 2016 (81 FR 81276), the EPA proposed to retain its current approach in establishing attainment dates for each nonattainment area classification, which run from the effective date of designations. This approach is codified at 40 CFR 51.1103 for the 2008 ozone NAAQs, and the EPA proposed to retain the same approach for the 2015 ozone NAAQS. In addition, the EPA proposed the maximum attainment dates for nonattainment areas in each classification, which for Moderate ozone nonattainment is 6 years.

[4] Note that the emissions projections in this NODA are consistent with the implementation of various state and federal regulations, and that any change to the future implementation of these regulations may impact these projections and related findings.

[5] The 2023 ozone source apportionment modeling was performed using meteorology for the period May through September in order to focus on transport when 8-hour ozone concentrations are typically high at most locations. This modeling did not include high winter ozone concentrations that have been observed in certain parts of the Western U.S. which are believed to result from the combination of strong wintertime inversions, large NOx and volatile organic compound (VOC) emissions from nearby oil and gas operations, increased ultraviolet (UV) radiation intensity due to reflection off of snow-covered surfaces and potentially other local factors.

and gas, non-EGU point sources) to 2023 as compared to the methods used in the final CSAPR Update to project emissions to 2017 include (1) the use of data from the U.S. Energy Information Administration Annual Energy Outlook 2016 (AEO 2016) to project activity data for onroad mobile sources and the growth in oil and gas emissions, (2) additional general refinements to the projection of oil and gas emissions, (3) incorporation of data from the Mid-Atlantic Regional Air Management Association (MARAMA) for projection of non-EGU emissions for states in that region, and (4) updated mobile source emissions for California.

For EGUs, the EPA has included several key updates to the Integrated Planning Model (IPM) and its inputs for the agency's 2023 EGU projections used for the air quality modeling provided in this NODA. The updated IPM assumptions incorporated in the EPA's Base Case v.5.16 capture several market trends occurring in the power sector today, and the 2023 EGU projections reflect a continuation of these trends. Notably, natural gas prices remain historically low and are expected to remain low in the foreseeable future given that gas production and pipeline capacity continue to increase while storage is already at an all-time high. These factors have contributed to record-setting U.S. natural gas production levels for the fifth consecutive year in 2015 and record-setting consumption levels for the sixth consecutive year. Additionally, electricity demand growth (including retail sales and direct use) has slowed in every decade since the 1950s, from 9.8 percent per year from 1949 to 1959 to 0.5 percent per year from 2000 to 2015. This trend is projected to continue: AEO 2016 projects lower growth than projected in AEO 2015. In addition, these updated emission projections account for a continuing decline in the cost of renewable energy technologies such as wind and solar, as well as the recently extended production and investment tax credits that support their deployment. All of these factors result in decreased generation and capacity from conventional coal steam relative to EPA's EGU analyses that preceded these updated IPM inputs. Over the past 10 years, coal-fired electricity generation in the U.S. has declined from providing roughly half of the nation's supply to about one-third, and has been replaced with lower-cost sources such as natural gas, wind, and solar.

The updated EGU projections also include the Clean Power Plan (CPP), 80 FR 64662 (October 23, 2015). The modeling for the CSAPR Update did not include the CPP due to the former rule's focus on the 2017 ozone season, *see* 81 FR at 74529. In the CSAPR Update rulemaking, the agency had identified several key factors and uncertainties associated with measuring the effects of the CPP in 2017, but explained that the EPA ''continues to believe that the modeling for the CPP . . . was useful and reliable with respect to the model years analyzed for [the CPP] (*i.e.,* 2020, 2025, and 2030).'' *Id.*. The period of focus for the modeling here is in the mid-2020s, which falls within the CPP's interim performance period, and the EPA therefore believes it is appropriate to include the CPP in the modeling.[6] The CPP is targeted at reducing carbon pollution, but on average, nationwide, the CPP would also reduce NO_X emissions from EGUs. The agency therefore anticipates that, if the CPP were removed from the modeling, the overall net effect could be higher levels of NO_X emissions, on average, and potentially higher ozone concentrations and contributions at receptors. However, note that NO_X emissions from EGUs represent just one part of the total NO_X inventory. In this regard, for many states it is possible that changes in EGU NO_X emissions on the order of what might be expected in 2023 due to the CPP may have limited impact on the concentration and contribution data in this NODA, which are based on total NO_X emissions.

As noted above, EGU emissions used for the air quality modeling in this NODA are based on IPM v5.16 projections. However, states may choose to use other EGU projections in developing their Good Neighbor SIPs. To continue to update and improve both EPA's and states' EGU projections, the EPA and state agencies, with the facilitation of multi-jurisdictional organizations (MJOs), have been collaborating in a technical engagement process to inform future-year emission projections for EGUs. The ongoing information exchange and data comparison have facilitated a clearer understanding of the capabilities and constraints of various tools and methods. This process will continue to inform how the EPA and states produce EGU emission projections to inform efforts to reduce ozone transport.

The EPA observes there are differences between recent emissions and generation data and the corresponding future-year projections in this NODA. The EPA's modeling directly simulates how future-year energy trends and economic signals affect the composition of the fleet. In the 2023 projections presented in this NODA, the EPA's modeling does not project the operation of a number of coal-fired and oil-fired units due to simulated future-year economic conditions, whether or not such capacity has publicly-released plans to retire.[7] Some other projection methodologies, such as the approach used by the Eastern Regional Technical Advisory Committee (ERTAC), purposefully maintain the current composition of the fleet except where operators have announced expected changes. Comparing these projections is informative because there is inherent uncertainty in anticipating any future-year composition of the EGU fleet, since analysts cannot know in advance exactly which operators will decide to retire which facilities at any given time. The EPA is soliciting comments on whether and, if so, how different projection techniques for EGUs would affect emissions and air quality in a manner that could further assist states with their analysis of transported air pollution.

B. Air Quality Modeling

For the final CSAPR Update, EPA used the Comprehensive Air Quality Model with Extensions (CAMx) v6.20 as the air quality model. After the EPA performed air quality modeling for the final CSAPR Update, Ramboll Environ, the CAMx model developer, released an updated version of CAMx (version 6.30). In addition, EPA has recently sponsored updates to the Carbon Bond chemical mechanism in CAMx v6.30 related to halogen chemistry reactions that deplete ozone in marine (*i.e.,* salt water) environments. The updated chemistry is included in a new version 6.32 which the EPA has used for this analysis. Specifically, EPA used CAMx v6.32 for the 2011 base year and 2023 future base case air quality modeling to identify receptors and quantify contributions for the 2015 NAAQS transport assessment. Information on this version of CAMx can be found in the Release Notes and User's Guide for CAMx v6.30 and in a

[6] The CPP is stayed by the Supreme Court. *West Virginia et al.* v. *EPA,* No. 15A773 (U.S. Feb. 9, 2016). It is currently unclear what adjustments, if any, will need to be made to the CPP's implementation timing in light of the stay.

[7] Note that much of this change in operation is projected to occur as early as 2020, which is the first year of the 25-year horizon over which EPA's model is optimizing. EPA's modeling adopts the assumption of perfect foresight, which implies that agents know precisely the nature and timing of conditions in future years (*e.g.,* future natural gas supply, future demand) that affect the ultimate cost of decisions along the way. With this perfect foresight, the model looks throughout the entire modeling horizon and selects the overall lowest cost solution for the power sector over that time.

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technical report describing the updated halogen chemistry in version 6.32. These documents can be found in the docket for this notice.[8] Details of the 2011 and 2023 CAMx model applications are described in the ''Air Quality Modeling Technical Support Document for the 2015 Ozone NAAQS Preliminary Interstate Transport Assessment'' (AQM TSD) which is available in the docket for this notice.

C. Information Regarding Potential 2023 Nonattainment and Maintenance Sites

The ozone predictions from the 2011 and 2023 CAMx model simulations were used to project 2009–2013 average and maximum ozone design values [9] to 2023 following the approach described in the EPA's draft guidance for attainment demonstration modeling.[10] Using the approach in the final CSAPR Update, we evaluated the 2023 projected average and maximum design values in conjunction with the most recent measured ozone design values (*i.e.,* 2013–2015) to identify sites that may warrant further consideration as potential nonattainment or maintenance sites in 2023.[11] If the approach in the CSAPR Update is applied to evaluate the projected design values, those sites with 2023 average design values that exceed the NAAQS and that are currently measuring nonattainment would be considered to be nonattainment receptors in 2023. Similarly, with the CSAPR Update approach, monitoring sites with a projected 2023 maximum design value that exceeds the NAAQS would be projected to be maintenance receptors in 2023. In the CSAPR Update approach, maintenance-only receptors include both those monitoring sites where the projected 2023 average design value is below the NAAQS, but the maximum design value is above the NAAQS, and monitoring sites with projected 2023 average design values that exceed the NAAQS, but for which current design values based on measured data do not exceed the NAAQS.

The base period 2009–2013 ambient and projected 2023 average and maximum design values and 2013–2015 and preliminary 2014–2016 measured design values at individual projected 2023 nonattainment receptor sites and maintenance-only receptor sites are provided in Tables 1 and 2, respectively.[12]

TABLE 1A—2009–2013 AND 2023 AVERAGE AND MAXIMUM DESIGN VALUES AND 2013–2015 AND PRELIMINARY 2014–2016 DESIGN VALUES (DVS) AT PROJECTED NONATTAINMENT RECEPTOR SITES IN THE EAST [13]

[Units are ppb]

Site ID	County	St	2009–2013 Average DV	2009–2013 Maximum DV	2023 Average DV	2023 Maximum DV	2013–2015 DV	2014–2016 DV
240251001	Harford	MD	90.0	93	71.3	73.7	71	73
360850067	Richmond	NY	81.3	83	71.2	72.7	74	76
361030002	Suffolk	NY	83.3	85	71.3	72.7	72	72
480391004	Brazoria	TX	88.0	89	74.4	75.3	80	75
482010024	Harris	TX	80.3	83	71.1	73.5	79	79
482011034	Harris	TX	81.0	82	71.6	72.5	74	73
484392003	Tarrant	TX	87.3	90	73.9	76.2	76	73
484393009	Tarrant	TX	86.0	86	72.0	72.0	78	75
551170006	Sheboygan	WI	84.3	87	71.0	73.3	77	79

TABLE 1B—2009–2013 AND 2023 AVERAGE AND MAXIMUM DESIGN VALUES AND 2013–2015 AND PRELIMINARY 2014–2016 DESIGN VALUES AT PROJECTED NONATTAINMENT RECEPTOR SITES IN THE WEST

[Units are ppb]

Site ID	County	St	2009–2013 Average DV	2009–2013 Maximum DV	2023 Average DV	2023 Maximum DV	2013–2015 DV	2014–2016 DV
60190007	Fresno	CA	94.7	95	78.9	79.1	86	86
60190011	Fresno	CA	93.0	96	77.8	80.3	85	88
60190242	Fresno	CA	91.7	95	79.2	82.0	86	86
60194001	Fresno	CA	90.7	92	73.0	74.0	89	91
60195001	Fresno	CA	97.0	99	79.1	80.8	88	94
60250005	Imperial	CA	74.7	76	72.8	74.1	77	76
60251003	Imperial	CA	81.0	82	78.5	79.5	78	76
60290007	Kern	CA	91.7	96	76.9	80.5	81	87
60290008	Kern	CA	86.3	88	71.2	72.6	78	81
60290014	Kern	CA	87.7	89	72.7	73.8	84	84
60290232	Kern	CA	87.3	89	72.7	74.1	78	77
60311004	Kings	CA	87.0	90	71.0	73.5	80	84
60370002	Los Angeles	CA	80.0	82	73.9	75.7	82	86
60370016	Los Angeles	CA	94.0	97	86.8	89.6	92	95

[8] CAMx v6.32 is a pre-release version of CAMx v6.40 which is expected to be made public by Ramboll Environ in late 2016 or early 2017.

[9] The ozone design value for a monitoring site is the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

[10] The December 3, 2014 ozone, fine particulate matter, and regional haze SIP modeling guidance is available at *http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf.*

[11] In determining compliance with the NAAQS, ozone design values are truncated to integer values. For example, a design value of 70.9 parts per billion (ppb) is truncated to 70 ppb which is attainment. In this manner, design values at or above 71.0 ppb are considered to exceed the NAAQS.

[12] The preliminary 2014–2016 design values are based on data from the Air Quality System (AQS) and AirNow and have not been certified by state agencies. Note that for some sites the preliminary 2014–2016 design values are higher than the corresponding data for 2013–2015.

[13] In this notice, the East includes all states from Texas northward to North Dakota and eastward to the East Coast. All states in the contiguous U.S. from New Mexico northward to Montana and westward to the West Coast are considered, for this notice, to be in the West.

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TABLE 1B—2009–2013 AND 2023 AVERAGE AND MAXIMUM DESIGN VALUES AND 2013–2015 AND PRELIMINARY 2014–2016 DESIGN VALUES AT PROJECTED NONATTAINMENT RECEPTOR SITES IN THE WEST—Continued

[Units are ppb]

Site ID	County	St	2009–2013 Average DV	2009–2013 Maximum DV	2023 Average DV	2023 Maximum DV	2013–2015 DV	2014–2016 DV
60371201	Los Angeles	CA	90.0	90	80.3	80.3	84	85
60371701	Los Angeles	CA	84.0	85	78.3	79.2	89	90
60376012	Los Angeles	CA	97.3	99	86.5	88.0	94	96
60379033	Los Angeles	CA	90.0	91	76.7	77.5	89	90
60392010	Madera	CA	85.0	86	71.7	72.6	81	83
60650012	Riverside	CA	97.3	99	83.0	84.4	92	93
60651016	Riverside	CA	100.7	101	85.1	85.3	98	97
60652002	Riverside	CA	84.3	85	72.2	72.8	81	81
60655001	Riverside	CA	92.3	93	79.4	80.0	87	87
60656001	Riverside	CA	94.0	98	78.4	81.7	90	91
60658001	Riverside	CA	97.0	98	86.7	87.6	92	95
60658005	Riverside	CA	92.7	94	82.9	84.1	85	91
60659001	Riverside	CA	88.3	91	73.3	75.6	84	86
60670012	Sacramento	CA	93.3	95	74.1	75.4	80	83
60710005	San Bernardino	CA	105.0	107	96.3	98.1	102	108
60710012	San Bernardino	CA	95.0	97	84.4	86.2	88	91
60710306	San Bernardino	CA	83.7	85	75.5	76.7	86	86
60711004	San Bernardino	CA	96.7	98	89.7	91.0	96	100
60712002	San Bernardino	CA	101.0	103	92.9	94.7	97	97
60714001	San Bernardino	CA	94.3	97	86.0	88.5	88	91
60714003	San Bernardino	CA	105.0	107	94.1	95.9	101	101
60719002	San Bernardino	CA	92.3	94	79.8	81.2	86	86
60719004	San Bernardino	CA	98.7	99	88.5	88.7	99	104
60990006	Stanislaus	CA	87.0	88	73.6	74.5	82	83
61070009	Tulare	CA	94.7	96	75.8	76.9	89	89
61072010	Tulare	CA	89.0	90	72.6	73.4	81	82

TABLE 2A—2009–2013 AND 2023 AVERAGE AND MAXIMUM DESIGN VALUES AND 2013–2015 AND PRELIMINARY 2014–2016 DESIGN VALUES AT PROJECTED MAINTENANCE-ONLY RECEPTOR SITES IN THE EAST

[Units are ppb]

Site ID	County	St	2009–2013 Average DV	2009–2013 Maximum DV	2023 Average DV	2023 Maximum DV	2013–2015 DV	2014–2016 DV
90013007	Fairfield	CT	84.3	89	69.4	73.2	83	81
90019003	Fairfield	CT	83.7	87	70.5	73.3	84	85
90099002	New Haven	CT	85.7	89	69.8	72.5	78	76
260050003	Allegan	MI	82.7	86	68.8	71.5	75	74
261630019	Wayne	MI	78.7	81	69.6	71.7	70	72
360810124	Queens	NY	78.0	80	69.9	71.7	69	69
481210034	Denton	TX	84.3	87	70.8	73.0	83	80
482010026	Harris	TX	77.3	80	68.6	71.0	68	68
482011039	Harris	TX	82.0	84	73.0	74.8	69	67
482011050	Harris	TX	78.3	80	69.5	71.0	71	70

TABLE 2B—2009–2013 AND 2023 AVERAGE AND MAXIMUM DESIGN VALUES AND 2013–2015 AND PRELIMINARY 2014–2016 DESIGN VALUES AT PROJECTED MAINTENANCE-ONLY RECEPTOR SITES IN THE WEST

[Units are ppb]

Site ID	County	St	2009–2013 Average DV	2009–2013 Maximum DV	2023 Average DV	2023 Maximum DV	2013–2015 DV	2014–2016 DV
60295002	Kern	CA	84.3	91	70.4	76.0	85	88
60296001	Kern	CA	84.3	86	70.6	72.0	79	81
60372005	Los Angeles	CA	78.0	82	70.6	74.3	74	83
61070006	Tulare	CA	81.7	85	69.1	71.8	84	84
61112002	Ventura	CA	81.0	83	70.7	72.4	77	77
80350004	Douglas	CO	80.7	83	69.6	71.6	79	77
80590006	Jefferson	CO	80.3	83	70.5	72.9	79	77
80590011	Jefferson	CO	78.7	82	69.7	72.7	80	80

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D. Information Regarding Quantification of Ozone Contributions

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique [14] to provide information regarding the expected contribution of 2023 base case NO_X and VOC emissions from all sources in each state to projected 2023 ozone concentrations at each air quality monitoring site. In the source apportionment model run, we tracked the ozone formed from each of the following contribution categories (*i.e.,* ''tags''):

- States—anthropogenic NO_X and VOC emissions from each of the contiguous 48 states and the District of Columbia tracked individually (emissions from all anthropogenic sectors in a given state were combined);
- Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);
- Boundary Concentrations—concentrations transported into the modeling domain from the lateral boundaries;
- Tribes—the emissions from those tribal lands for which we have point source inventory data in the 2011 NEI (we did not model the contributions from individual tribes);
- Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (contributions from Canada and Mexico were not modeled separately);
- Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and
- Offshore—combined emissions from offshore marine vessels and offshore drilling platforms (*i.e.,* not by state).

The CAMx source apportionment model simulation was performed for the period May 1 through September 30 using the 2023 future base case emissions and 2011 meteorology for this time period. The hourly contributions [15] from each tag were processed to obtain the 8-hour average contributions corresponding to the time period of the 8-hour daily maximum concentration on each day in the 2023 model simulation. This step was performed for those model grid cells containing monitoring sites in order to obtain 8-hour average contributions for each day at the location of each site. The model-predicted contributions were applied in a relative sense to quantify the contributions to the 2023 average design value at each site. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the AQM TSD. The resulting 2023 contributions from each tag to each monitoring site are provided in a file in the docket for this notice.[16] The largest contributions from each state to 2023 downwind nonattainment receptors and to downwind maintenance-only receptors are provided in Tables 3–1 and 3–2, respectively.

TABLE 3–1—LARGEST CONTRIBUTION FROM EACH STATE TO DOWNWIND 8-HOUR OZONE NONATTAINMENT RECEPTORS

[Units are ppb]

Upwind states	Largest contribution to a downwind nonattainment receptor	Upwind states	Largest contribution to a downwind nonattainment receptor
Alabama	0.37	Montana	0.09
Arizona	0.74	Nebraska	0.37
Arkansas	1.16	Nevada	0.62
California	0.19	New Hampshire	0.01
Colorado	0.32	New Jersey	11.73
Connecticut	0.43	New Mexico	0.18
Delaware	0.55	New York	0.19
District of Columbia	0.70	North Carolina	0.43
Florida	0.49	North Dakota	0.15
Georgia	0.38	Ohio	2.38
Idaho	0.07	Oklahoma	2.39
Illinois	14.92	Oregon	0.61
Indiana	7.14	Pennsylvania	9.11
Iowa	0.43	Rhode Island	0.00
Kansas	1.01	South Carolina	0.16
Kentucky	2.15	South Dakota	0.08
Louisiana	2.87	Tennessee	0.52
Maine	0.01	Texas	1.92
Maryland	1.73	Utah	0.24
Massachusetts	0.05	Vermont	0.00
Michigan	1.77	Virginia	5.04
Minnesota	0.43	Washington	0.15
Mississippi	0.56	West Virginia	2.59
Missouri	1.20	Wisconsin	0.47
		Wyoming	0.31

[14] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

[15] Ozone contributions from anthropogenic emissions under ''NO_X-limited'' and ''VOC-limited'' chemical regimes were combined to obtain the net contribution from NO_X and VOC anthropogenic emissions in each state.

[16] The file containing the contributions is named: ''2015 O3 NAAQS Transport Assessment_Design Values & Contributions.''

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TABLE 3–2—LARGEST CONTRIBUTION FROM EACH STATE TO DOWNWIND 8-HOUR OZONE MAINTENANCE RECEPTORS

[Units are ppb]

Upwind states	Largest contribution to a downwind maintenance receptor	Upwind states	Largest contribution to a downwind maintenance receptor
Alabama	0.48	Montana	0.11
Arizona	0.52	Nebraska	0.41
Arkansas	2.20	Nevada	0.43
California	2.03	New Hampshire	0.02
Colorado	0.25	New Jersey	8.65
Connecticut	0.36	New Mexico	0.41
Delaware	0.38	New York	15.36
District of Columbia	0.08	North Carolina	0.43
Florida	0.22	North Dakota	0.13
Georgia	0.31	Ohio	3.82
Idaho	0.16	Oklahoma	1.30
Illinois	21.69	Oregon	0.17
Indiana	6.45	Pennsylvania	6.39
Iowa	0.60	Rhode Island	0.02
Kansas	0.64	South Carolina	0.15
Kentucky	1.07	South Dakota	0.06
Louisiana	3.37	Tennessee	0.69
Maine	0.00	Texas	2.49
Maryland	2.20	Utah	1.32
Massachusetts	0.11	Vermont	0.01
Michigan	1.76	Virginia	2.03
Minnesota	0.34	Washington	0.11
Mississippi	0.65	West Virginia	0.92
Missouri	2.98	Wisconsin	1.94
		Wyoming	0.92

In CSAPR and the CSAPR Update, the EPA used a contribution screening threshold of 1 percent of the NAAQS to identify upwind states that may significantly contribute to downwind nonattainment and/or maintenance problems and which warrant further analysis to determine if emissions reductions might be required from each state to address the downwind air quality problem. The EPA determined that 1 percent was an appropriate threshold to use in the analysis for those rulemakings because there were important, even if relatively small, contributions to identified nonattainment and maintenance receptors from multiple upwind states mainly in the eastern U.S. The agency has historically found that the 1 percent threshold is appropriate for identifying interstate transport linkages for states collectively contributing to downwind ozone nonattainment or maintenance problems because that threshold captures a high percentage of the total pollution transport affecting downwind receptors.

Based on the approach used in CSAPR and the CSAPR Update, upwind states that contribute ozone in amounts at or above the 1 percent of the NAAQS threshold to a particular downwind nonattainment or maintenance receptor would be considered to be ''linked'' to that receptor in step 2 of the CSAPR framework for purposes of further analysis in step 3 to determine whether and what emissions from the upwind state contribute significantly to downwind nonattainment and interfere with maintenance of the NAAQS at the downwind receptors. For the 2015 ozone NAAQS, the value of a 1 percent threshold would be 0.70 ppb. The individual upwind state to downwind receptor ''linkages'' and contributions based on a 0.70 ppb threshold are identified in the AQM TSD for this notice.

The EPA notes that, when applying the CSAPR framework, an upwind state's linkage to a downwind receptor alone does not determine whether the state significantly contributes to nonattainment or interferes with maintenance of a NAAQS to a downwind state. While the 1 percent screening threshold has been traditionally applied to evaluate upwind state linkages in eastern states where such collective contribution was identified, the EPA noted in the CSAPR Update that, as to western states, there may be geographically specific factors to consider in determining whether the 1 percent screening threshold is appropriate. For certain receptors, where the collective contribution of emissions from one or more upwind states may not be a considerable portion of the ozone concentration at the downwind receptor, the EPA and states have considered, and could continue to consider, other factors to evaluate those states' planning obligation pursuant to the Good Neighbor provision.[17] However, where the collective contribution of emissions from one or more upwind states is responsible for a considerable portion of the downwind air quality problem, the CSAPR framework treats a contribution from an individual state at or above 1 percent of the NAAQS as significant, and this reasoning applies regardless of where the receptor is geographically located.

III. Analytic Information Available for Public Comment

The EPA has placed key information related to the air quality model applications into the electronic docket for this notice. This information includes the AQM TSD, an Excel file which contains the 2009–2013 base period and 2023 projected average and maximum ozone design values at individual monitoring sites and the

[17] *See, e.g.,* 81 FR 31513 (May 19, 2016) (approving Arizona Good Neighbor SIP addressing 2008 ozone NAAQS based on determination that upwind states would not collectively contribute to a considerable portion of the downwind air quality problem).

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ozone contributions to individual monitoring sites from anthropogenic emissions in each state and from the other individual categories included in the source apportionment modeling. Also in the docket for this notice are a number of emission summaries by sector, state, county, source classification code, month, unit, day, and control program. In addition, the raw emission inventory files, ancillary data, and scripts used to develop the air quality model-ready emissions which are not in a format accepted by the electronic docket are available from the Air Emissions Modeling Web site for the Version 6.3 Platform at *https://www.epa.gov/air-emissions-modeling/2011-version-63-platform.* Electronic copies of the emissions and non-emissions air quality modeling input files, the CAMx v6.32 model code and run scripts, and the air quality modeling output files from the 2011 and 2023 air quality modeling performed for the 2015 NAAQS ozone transport assessment can be obtained by contacting Norm Possiel at *possiel.norm@epa.gov.*

The EPA is requesting comment on the components of the 2011 air quality modeling platform, the methods for projecting 2023 ozone design value concentrations and the methods for calculating ozone contributions. The EPA is also seeking comment on the methods used to project emissions to future years, where 2023 is an example of such a year. Specifically, comments are requested regarding new datasets, impacts of existing and planned federal, state, and local control programs on emissions, and new methods that could be used to prepare more representative emissions projections. That is, EPA is seeking comments on the projection approach and data sets that are potentially useful for computing projected emissions. Commenters wishing to comment on inventory projection methods should submit to the docket comments that describe an alternative approach to the existing methods, along with documentation describing why that method is an improvement over the existing method. Summaries of the base and projected future year emission inventories are provided in the docket to aid in the review of these data. As indicated above, the comment period for this notice is 90 days from the date of publication in the **Federal Register.**

Dated: December 28, 2016.

Stephen Page,

Director, Office of Air Quality Planning and Standards.

[FR Doc. 2017–00058 Filed 1–5–17; 8:45 am]

BILLING CODE 6560–50–P

FARM CREDIT ADMINISTRATION

Farm Credit Administration Board; Sunshine Act; Regular Meeting

AGENCY: Farm Credit Administration.

SUMMARY: Notice is hereby given, pursuant to the Government in the Sunshine Act, of the regular meeting of the Farm Credit Administration Board (Board).

DATE AND TIME: The regular meeting of the Board will be held at the offices of the Farm Credit Administration in McLean, Virginia, on January 12, 2017, from 9:00 a.m. until such time as the Board concludes its business.

FOR FURTHER INFORMATION CONTACT: Dale L. Aultman, Secretary to the Farm Credit Administration Board, (703) 883–4009, TTY (703) 883–4056.

ADDRESSES: Farm Credit Administration, 1501 Farm Credit Drive, McLean, Virginia 22102–5090. Submit attendance requests via email to *VisitorRequest@FCA.gov.* See **SUPPLEMENTARY INFORMATION** for further information about attendance requests.

SUPPLEMENTARY INFORMATION: Parts of this meeting of the Board will be open to the public (limited space available), and parts will be closed to the public. Please send an email to *VisitorRequest@FCA.gov* at least 24 hours before the meeting. In your email include: Name, postal address, entity you are representing (if applicable), and telephone number. You will receive an email confirmation from us. Please be prepared to show a photo identification when you arrive. If you need assistance for accessibility reasons, or if you have any questions, contact Dale L. Aultman, Secretary to the Farm Credit Administration Board, at (703) 883–4009. The matters to be considered at the meeting are:

Open Session

A. Approval of Minutes

- December 8, 2016

B. New Business

- Draft Third Amended and Restated Market Access Agreement to be entered into by the Farm Credit System Banks and the Federal Farm Credit Banks Funding Corporation

C. Reports

- Auditor's Report on FCA FY 2016/2015 Financial Statements

Closed Session*

- Executive Meeting with Auditors

* Session Closed-Exempt pursuant to 5 U.S.C. Section 552b(c)(2).

Dated: January 4, 2017.

Dale L. Aultman,

Secretary, Farm Credit Administration Board.

[FR Doc. 2017–00131 Filed 1–4–17; 11:15 am]

BILLING CODE 6705–01–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisitions of Shares of a Bank or Bank Holding Company

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire shares of a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than January 24, 2017.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

1. *Paul James Sentry,* Verona, Wisconsin; to acquire more than 25 percent of Deerfield Financial Corporation, Madison, Wisconsin, and thereby indirectly control Bank of Deerfield, Deerfield, Wisconsin.

B. Federal Reserve Bank of Minneapolis (Jacquelyn K. Brunmeier, Assistant Vice President) 90 Hennepin Avenue, Minneapolis, Minnesota 55480–0291:

1. *Timothy Schneider, individually and as trustee of the Timothy Schneider Irrevocable Trust (''Trust''),* both in Adams, Minnesota; to acquire more than 10 percent of Adams Bancshares, Inc., and thereby indirectly control United Farmers State Bank, both in Adams, Minnesota.

C. Federal Reserve Bank of Kansas City (Dennis Denney, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. *Clay Muegge and Chad Muegge,* both of Lamont, Oklahoma; to retain shares of State Exchange Bancshares, Inc., and thereby indirectly retain shares of State Exchange Bank, both of Lamont, Oklahoma; and for approval as members of the Muegge Family Group that controls State Exchange Bancshares, Inc.

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(d) A project description, including the timeframe within which the project is to be started and completed;

(e) The terms and conditions of the agreement, including any reporting requirements;

(f) All obligations of the parties; and

(g) The signatures of appropriate individuals authorized to bind the applicant and BOEM.

§ 583.305 What is the effective date of an agreement?

The agreement will become effective on the date when all parties to the agreement have signed it.

§ 583.306 How will BOEM enforce the agreement?

(a) Failure to comply with any applicable law or any provision, term, or condition of the agreement may result in the termination of the agreement and/or a referral to an appropriate Federal and/or State agency/agencies for enforcement. Termination of the agreement for noncompliance will be in the sole discretion of the Director.

(b) The failure to comply in a timely and satisfactory manner with any provision, term or condition of the agreement may delay or prevent BOEM's approval of future requests for use of OCS sand, gravel and shell resources on the part of the parties to the agreement.

§ 583.307 What is the term of the agreement?

(a) An agreement will terminate upon the following, whichever occurs first:

(1) The agreement expires by its own terms, unless the term is extended prior to expiration under § 583.309;

(2) The project is terminated, as set forth in § 583.310; or

(3) A party to the agreement notifies BOEM, in writing, that sufficient OCS sand, gravel and shell resources, up to the amount authorized in the agreement, have been obtained to complete the project.

(b) Absent extraordinary circumstances, no agreement will be for a term longer than 5 years from its effective date.

§ 583.308 What debarment or suspension obligations apply to transactions and contracts related to a project?

The parties to an agreement must ensure that all contracts and transactions related to an agreement issued under this part comply with 2 CFR part 180 and 2 CFR part 1400.

§ 583.309 What is the process for modifying the agreement?

(a) Unless otherwise provided for in the agreement, the parties to the agreement may submit to BOEM a written request to extend, modify, or change an agreement. BOEM is under no obligation to extend an agreement and cannot be held liable for the consequences of the expiration of an agreement. With the exception of paragraph (b) of this section, any such requests must be made at least 180 days before the term of the agreement expires. BOEM will respond to the request for modification within 30 days of receipt and request any necessary information and evaluations to comply with 30 CFR 583.301. BOEM may approve the request, disapprove it, or approve it with modifications subject to the requirements of 30 CFR 583.301.

(1) If BOEM approves a request to extend, modify or change an agreement, BOEM will draft an agreement modification for review by the parties to the agreement in the form of an amendment to the original agreement. The amendment will include:

(i) The agreement number, as assigned by BOEM;

(ii) The modification(s) agreed to;

(iii) Any additional mitigation required; and

(iv) The signatures of the parties to the agreement and BOEM.

(2) If BOEM disapproves a request to extend, modify, or change an agreement, BOEM will inform the parties to the agreement of the reasons in writing. Parties to the agreement may ask the BOEM Director for reconsideration in accordance with 30 CFR 583.105.

(b) By written request, for strictly minor modifications that do not change the substance of the project or the analyzed environmental effects of the project, including but not limited to, the change of a business address, the substitution of a different Federal, State or local government agency contact, or an extension of less than 30 days, parties to the agreement may memorialize the minor modification in a letter from BOEM to the parties indicating the request has been granted.

§ 583.310 When can the agreement be terminated?

(a) The Director will terminate any agreement issued under this part upon proof that it was obtained by fraud or misrepresentation, after notice and an opportunity to be heard has been afforded to the parties of the agreement.

(b) The Director may immediately suspend and subsequently terminate any agreement issued under this part when:

(1) There is noncompliance with the agreement, pursuant to 30 CFR 583.306(a); or

(2) It is necessary for reasons of national security or defense; or

(3) The Director determines that:

(i) Continued activity under the agreement would cause serious harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(iii) The advantages of termination outweigh the advantages of continuing the agreement.

(c) The Director will immediately notify the parties to the agreement of the suspension or termination. The Director will also mail a letter to the parties to the agreement at their record post office address with notice of any suspension or termination and the cause for such action.

(d) In the event that BOEM terminates an agreement under this section, none of the parties to the agreement will be entitled to compensation as a result of expenses or lost revenues that may result from the termination.

[FR Doc. 2016–06163 Filed 3–21–16; 8:45 am]

BILLING CODE 4310–MR–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2015–0793; FRL–9944–08–Region 9]

Partial Approval and Partial Disapproval of Air Quality State Implementation Plans; Arizona; Infrastructure Requirements To Address Interstate Transport for the 2008 Ozone NAAQS

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to partially approve and partially disapprove a State Implementation Plan (SIP) revision submitted by the Arizona Department of Environmental Quality on December 27, 2012, and supplemented on December 3, 2015, to address the interstate transport requirements of Clean Air Act (CAA or Act) section 110(a)(2)(D) with respect to the 2008 ozone (O_3) national ambient air quality standard (NAAQS). We are proposing to approve the portion of the Arizona SIP pertaining to significant contribution to

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nonattainment or interference with maintenance in another state and proposing to disapprove the portion of Arizona's SIP pertaining to interstate transport visibility requirements. EPA's rationale for proposing to partially approve and partially disapprove Arizona's December 27, 2012 SIP revision and December 3, 2015 supplement is described in this notice. EPA previously took two separate actions on Arizona's December 27, 2012 submittal, on July 14, 2015 and August 10, 2015. We are taking comments on this proposal and plan to follow with a final action no later than June 7, 2016.

DATES: Written comments must be received on or before April 21, 2016.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R09–OAR–2015–0793 at *http://www.regulations.gov,* or via email to *Clancy.Maeve@epa.gov.* For comments submitted at Regulations.gov, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. For either manner of submission, the EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Maeve Clancy, EPA Region IX, (415) 947–4105, *Clancy.Maeve@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, the terms "we," "us," and "our" refer to EPA.

Table of Contents

I. Background

CAA sections 110(a)(1) and (2) require states to address basic SIP requirements to implement, maintain and enforce the NAAQS no later than three years after the promulgation of a new or revised standard. Section 110(a)(2) outlines the specific requirements that each state is required to address in this SIP submission that collectively constitute the "infrastructure" of a state's air quality management program. SIP submittals that address these requirements are referred to as "infrastructure SIPs" (I–SIP). In particular, CAA section 110(a)(2)(D)(i)(I) requires that each SIP for a new or revised NAAQS contain adequate provisions to prohibit any source or other type of emissions activity within the state from emitting air pollutants that will "contribute significantly to nonattainment" (prong 1) or "interfere with maintenance" (prong 2) of the applicable air quality standard in any other state. CAA section 110(a)(2)(D)(i)(II) requires SIP provisions that prevent interference with measures required to be included in the applicable implementation plan for any other State under part C to prevent significant deterioration of air quality (prong 3) or to protect visibility (prong 4). This action addresses the section 110(a)(2)(D)(i) requirements of prongs 1, 2 and 4 with respect to Arizona's I–SIP submissions.

On March 27, 2008, EPA issued a revised NAAQS for ozone.[1] This action triggered a requirement for states to submit an I–SIP to address the applicable requirements of section 110(a)(2) within three years of issuance of the revised NAAQS.

On September 13, 2013, EPA issued "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)," which provides "advice on the development of infrastructure SIPs for the 2008 ozone NAAQS . . . as well as infrastructure SIPs for new or revised NAAQS promulgated in the future." [2] EPA followed that guidance with an additional memo specific to 110(a)(2)(D)(i)(I) (prongs 1 and 2) requirements for the 2008 O_3 standard on January 22, 2015 entitled, "Information on the Interstate Transport "Good Neighbor" Provision for the 2008 Ozone NAAQS Under CAA Section 110(a)(2)(D)(i)(I)" (2015 transport memo).[3] While this memo did not provide specific guidance to western states on interstate transport, it did contain preliminary modeling information for western states. This 2015 transport memo, following the approach used in EPA's prior Cross-State Air Pollution Rule (CSAPR),[4] provided data identifying ozone monitoring sites that were projected to be in nonattainment or have maintenance problems for the 2008 ozone NAAQS in 2018. Also, EPA provided the projected contribution estimates from 2018 anthropogenic oxides of nitrogen (NO_X) and volatile organic compound (VOC) emissions in each state to ozone concentrations at each of the projected sites.

On August 4, 2015, EPA published a **Federal Register** Notice entitled, "Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone NAAQS." [5] This Notice of Data Availability (NODA) is an update of the preliminary air quality modeling data that was released January 22, 2015. This NODA provided data identifying ozone monitoring sites that are projected to be nonattainment or have maintenance problems (following the CSAPR approach) for the 2008 ozone NAAQS in 2017.[6] Also, EPA provided the projected ozone contribution estimates from 2017 anthropogenic NO_X and VOC emissions in each state to ozone concentrations at each of the projected monitoring sites. The 2017 modeling released in the NODA was used to support EPA's proposed update to CSAPR to address CAA section 110(a)(2)(D)(i)(I) requirements with respect to the 2008 ozone NAAQS in the eastern U.S. ("CSAPR Update Rule").[7] CSAPR and its predecessor transport rules, the NO_X SIP Call and CAIR, were designed to address the collective contributions from the 37 states in the eastern U.S. and ozone contribution information was not calculated to or from the 11 states in the western U.S. The proposed CSAPR Update Rule and the supportive

[1] National Ambient Air Quality Standards for Ozone; Final Rule, 73 FR 16436 (March 27, 2008).

[2] Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, to Regional Air Division Directors, Regions 1–10 (September 13, 2013).

[3] Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, to Regional Air Division Directors, Regions 1–10 (January 22, 2015).

[4] Cross-State Air Pollution Rule, 76 FR 48208 (Aug. 8, 2011).

[5] Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS), 80 FR 46271 (August 4, 2015).

[6] The EPA adopted 2017 as the analytic year for the updated ozone modeling information. See 80 FR 46273.

[7] Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 80 FR 75706 (December 3, 2015).

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modeling released in the NODA include data relevant to the West but did not evaluate potential interstate transport impacts in 11 western states, including Arizona. In this action, we are utilizing these data to evaluate the state's submittals and any interstate transport obligations under section 110(a)(2)(D)(i)(I).

EPA is obligated, pursuant to a judgement issued by the Northern District of California in *Sierra Club* vs. *McCarthy,* to take final action on 110(a)(2)(D) prongs 1, 2, and 4 of Arizona's December 2012 SIP revision by June 7, 2016.[8] In our July 2015 partial approval and partial disapproval of Arizona's I–SIP submittals for the 2008 Pb and 2008 ozone NAAQS, for the I–SIP elements C, D, J, and K, EPA partially approved and partially disapproved the submittals for purposes of 110(a)(2)(D)(i)(II) prong 3 and partially approved and partially disapproved the submittals for purposes of 110(a)(2)(D)(ii) (relating to CAA sections 115 and 126). We also stated our intention to propose action on the I–SIP for the 2008 ozone NAAQS 110(a)(2)(D)(i) prongs 1, 2, and 4 in a separate action.[9] We subsequently took action on I–SIP elements A, B, E–H, L, and M for the 2008 Pb and 2008 ozone NAAQS in August 2015.[10]

II. State Submittals

On December 27, 2012, the Arizona Department of Environmental Quality (ADEQ) submitted its 2008 ozone NAAQS I–SIP (2012 submittal). This submittal briefly summarized the CAA requirements of sections 110(a)(2)(D)(i), 110(a)(2)(D)(ii), and EPA's I–SIP action for the previous 1997 ozone NAAQS, but as to prongs 1, 2, and 4 did not identify or address any potential interstate transport impacts between Arizona and other states or interstate transport visibility requirements for the 2008 ozone NAAQS. On December 3, 2015, ADEQ submitted a supplement to the 2012 submittal addressing 110(a)(2)(D)(i) prongs 1, 2, and 4.[11] For the purposes of this action, we will refer to the supplemental submittal as the ''2015 submittal.'' The 2015 submittal represents ADEQ's comprehensive analysis of ozone transport from Arizona to surrounding states and addresses potential interstate transport linkages between Arizona and the El Centro, CA and Los Angeles, CA nonattainment receptors that were identified in the 2015 ozone transport memo and the 2015 NODA. The 2015 submittal also addresses the requirements of prong 4 (interstate transport visibility requirements).

In the 2015 submittal, ADEQ summarizes the state's impact on downwind states. While Arizona's impact on the El Centro and Los Angeles monitors is in each case above 1%, Arizona impacts only one of the seven projected nonattainment or maintenance receptors in the Los Angeles area, and contributes less than 1% to all other maintenance and nonattainment receptors. ADEQ further states that, ''In eastern states, the EPA has chosen a 1% of the standard threshold as a significant contribution. However, Arizona considers the southwest to be different.'' The state goes on to say that, ''It is unclear at this point what threshold is significant for southwestern states.'' EPA's assessment of these statements is described in the next section. The submittal also summarizes sources of VOCs and NO_X statewide, outlining the controls on anthropogenic emission sources with a focus on efforts to reduce NO_X through controls implemented via Arizona's Regional Haze SIP and EPA's Regional Haze Federal Implementation Plan (FIP) and current and future Maricopa County stationary source controls in the Arizona SIP. For more information on Arizona's source categories and emissions controls, please see the technical support document (TSD) associated with today's proposed rulemaking.

III. EPA's Assessment

110(a)(2)(D)(i)(I) Prong 1 and Prong 2

EPA proposes to approve Arizona's SIP submissions pertaining to CAA section 110(a)(2)(D)(i)(I), prongs 1 and 2, with respect to the 2008 ozone NAAQS. As explained below, EPA's proposal is based on the state's submission and EPA's analysis of several factors and available data.

To determine whether the CAA section 110(a)(2)(D)(i)(I), prongs 1 and 2 requirement is satisfied, EPA first must determine whether a state's emissions will contribute significantly to nonattainment or interfere with maintenance of a NAAQS in other states. If a state is determined not to make such contribution or interfere with maintenance of the NAAQS, then EPA can conclude that the state's SIP complies with the requirements of section 110(a)(2)(D)(i)(I). In several prior federal rulemakings interpreting section 110(a)(2)(D)(i)(I), EPA has evaluated whether a state will significantly contribute to nonattainment or interfere with maintenance of a NAAQS by first identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS.[12] EPA has then determined which upwind states contribute to these identified air quality problems in amounts sufficient to warrant further evaluation to determine if the state can make emission reductions to reduce its contribution. CSAPR and the proposed CSAPR Update used a screening threshold (1% of the NAAQS) to identify such contributing upwind states warranting further review and analysis. EPA's NODA used air quality modeling to evaluate contributions from upwind states to downward receptors. Applying the methodology used in CSAPR, the NODA modeling information indicates that emissions from Arizona contribute amounts exceeding the CSAPR 1% threshold at two projected downwind nonattainment sites in El Centro, California, and Los Angeles, California.[13]

EPA notes that it disagrees with ADEQ's contention that it is unclear what screening threshold is significant for southwestern states when addressing interstate transport contributions. EPA believes contribution from an individual state equal to or above 1% of the NAAQS could be considered significant where the collective contribution of emissions from one or more upwind states is responsible for a considerable portion of the downwind air quality problem regardless of where the receptor is geographically located.[14]

Accordingly, although EPA's modeling indicates that emissions from

[8] See Judgment, Sierra Club v. McCarthy, Case 4:14–cv–05091–YGR (N.D. Cal. May 15, 2015).

[9] Partial Approval and Partial Disapproval of Air Quality State Implementation Plans; Arizona; Infrastructure Requirements for Lead and Ozone. 80 FR 40905 (July 14, 2015).

[10] Approval and Promulgation of State Implementation Plans; Arizona; Infrastructure Requirements for the 2008 Lead (Pb) and the 2008 8-Hour Ozone National Ambient Air Quality Standards (NAAQS). 80 FR 47859 (August 10, 2015).

[11] ''Arizona State Implementation Plan Revisions for 2008 Ozone and 2010 Nitrogen Dioxide Under Clean Air Act Section 110(a)(2)(D) . . .'' Signed December 3, 2015. And see email from Heidi Haggerty of ADEQ. ''AZ 2015 Ozone Transport I–SIP Submittal Clarification.'' Sent December 9, 2015.

[12] NO_X SIP Call, Final Rule, 63 FR 57371 (October 27, 1998); Clean Air Interstate Rule (CAIR), Final Rule, 70 FR 25172 (May 12, 2005); Cross-State Air Pollution Rule (CSAPR), Final Rule, 76 FR 48208 (August 8, 2011); CSAPR Update Rule, Proposed Rule, 80 FR 75706 (Dec. 3, 2015).

[13] Data file with 2017 Ozone Contributions. Included in docket for: Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS), 80 FR 46271 (August 4, 2015).

[14] EPA has previously noted there may be additional criteria to evaluate regarding collective contribution of transported air pollution at certain locations in the West. See footnotes 4 and 7.

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Arizona contribute above the 1% threshold to two projected downwind air quality problems, EPA examined several factors to determine whether Arizona should be considered to significantly contribute to nonattainment or interfere with maintenance of the NAAQS at those sites, including the air quality and contribution modeling, receptor data, and the statewide measures reducing emissions of VOCs and NO_X. EPA notes that no single piece of information is by itself dispositive of the issue for purposes of this analysis. Instead, EPA has considered the total weight of all the evidence taken together to evaluate whether Arizona significantly contributes to nonattainment or interferes with maintenance of the 2008 ozone NAAQS in those areas.

One such factor that EPA considers relevant to determining the nature of a projected receptor's interstate transport problem is the magnitude of ozone attributable to transport from all upwind states collectively contributing to the air quality problem. In CSAPR and the CSAPR Update Rule, EPA used the 1% air quality threshold to identify linkages between upwind states and downwind maintenance receptors. States whose contributions to a specific receptor meet or exceed the threshold were considered to be linked to that receptor. The linked states' emissions (and available emission reductions) were then analyzed further as a second step to EPA's contribution analysis. States whose contributions to all receptors were below the 1% threshold did not require further evaluation to address interstate transport and we therefore found those states were determined to make insignificant contributions to downwind air quality. Therefore, the states below the threshold do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states. EPA used the 1% threshold in the East because prior analysis showed that, in general, nonattainment problems result from a combined impact of relatively small individual contributions from upwind states, along with contributions from in-state sources. EPA has observed that a relatively large portion of the air quality problem at most ozone nonattainment and maintenance receptors in the East is the result of the collective contribution from a number of upwind states.

Specifically, EPA found the total upwind states' contribution to ozone concentration (from linked and unlinked states) based on modeling for 2017 ranges from 17% to 67% to identified downwind air quality problems in the East, with between 4 and 12 states each contributing above 1% to the downwind air quality problem.[15] [16] Thus, irrespective of the 1% air quality threshold in the East, EPA has found that the collective contributions from upwind states represent a large portion of the ozone concentrations at projected air quality problems. Further, in the East, EPA found that the 1% threshold is appropriate to capture a high percentage of the total pollution transport affecting downwind receptors. By comparison, according to EPA's modeling, the total upwind (linked or unlinked) states' contribution to ozone concentration at the projected nonattainment sites in El Centro, California and Los Angeles, California, is comparatively small, with only one state contributing above 1% to the downwind air quality problem.

Arizona is the only state that contributes greater than the 1% threshold to the projected 2017 levels of the 2008 ozone NAAQS at the El Centro receptor. The total contribution from all states to the El Centro receptor is 4.4% of the total ozone concentration at this receptor. Arizona is also the only state that contributes greater than 1% to the projected 2017 levels of the 2008 ozone NAAQS at the Los Angeles receptor, and the total contribution from all states is 2.5% of the ozone concentration at this receptor. EPA believes that a 4.4% and 2.5% cumulative ozone contribution from all upwind states is negligible, particularly when compared to the relatively large contributions from upwind states in the East or in certain other areas of the West. For these reasons, EPA believes the emissions that result in transported ozone from upwind states have limited impacts on the projected air quality problems in El Centro, California and Los Angeles, California, and therefore should not be treated as receptors for purposes of determining the interstate transport obligations of upwind states under section 110(a)(2)(D)(i)(I).

Additionally, EPA has evaluated the Arizona VOC and NO_X emissions inventory and emissions projections and agrees that emissions will be decreasing over time. Given that emissions within the state are expected to decrease over time due to regional haze measures, Federal engine and fuel standards, and other Federal, State, and local rules,[17] EPA believes that the Arizona SIP contains adequate provisions to ensure that air emissions in Arizona do not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in California or any other state in the future.

The modeling data show that Arizona contributes either less than 1% of the NAAQS to projected air quality problems in other states, or where it contributes above 1% of the NAAQS to a projected downwind air quality problem in California, EPA proposes to find, based on the overall weight of evidence, that these particular receptors are not significantly impacted by transported ozone from upwind states. Emissions reductions from Arizona are not necessary to address interstate transport because the total collective upwind state ozone contribution to these receptors is relatively low compared to the air quality problems typically addressed by the good neighbor provision. Additionally, Arizona has demonstrated that both VOC and NO_X emissions are going down and will continue to go down. EPA therefore believes that Arizona's contributions to downwind receptors in California are considered insignificant. EPA proposes to find that Arizona does not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in other states.

110(a)(2)(D)(i)(II) Prong 4

EPA believes that ozone precursor emissions of NO_X may contribute to visibility impairment in Class I areas. EPA's 2013 I–SIP guidance clarifies that a state can rely upon a fully EPA-approved Regional Haze SIP to satisfy the requirements of this sub-element. Arizona's Regional Haze SIP shows that sources in Arizona impact visibility in Colorado (Great Sand Dunes National Monument, Mesa Verde National Park, Black Canyon of the Gunnison National Park, La Garita Wilderness, and Weminuche Wilderness), New Mexico (Bandelier National Monument, San Pedro Parks Wilderness, Pecos Wilderness, Bosque del Apache National Wildlife Reserve, and Gila Wilderness), and Utah (Zion National Park, Bryce Canyon National Park, Capitol Reef National Park, Canyonlands National Park, and Arches

[15] The stated range is based on the highest nonattainment or maintenance receptor in each area. All nonattainment and maintenance receptors had upwind contributions of well over 17%, except for some receptors in Dallas and Houston.

[16] Memo to Docket from EPA, Air Quality Policy Division. "Contribution Analysis of Receptors in the Updated CSAPR Proposal." March 10, 2016.

[17] See TSD for details on other emissions control measures.

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National Park).[18] Arizona's Regional Haze SIP is not fully approved by EPA. Instead, Arizona's 2012 and 2015 submittals rely, in part, on regulations imposed by FIPs to address visibility impairment in Class 1 Areas caused by NO_X, SO_2, and PM. These regulations include emission limits on the following facilities: Arizona Public Service Cholla Power Plant,[19] Salt River Project Coronado Generating Station,[20] Freeport McMoran Miami Smelter,[21] ASARCO Hayden Smelter,[22] Sundt Generating Station Unit 4,[23] and Nelson Lime Plant Kilns 1 and 2.[24] Emissions limits have been incorporated into the state SIP, replacing a previous FIP, at AEPCO Apache Station Units 1, 2, and 3.[25]

Because Arizona's 2012 and 2015 submittals rely in part on FIPs to address interstate transport visibility requirements, they do not meet the requirements of prong 4 for the 2008 ozone NAAQS. However, because FIPs are already in place, no additional FIP obligation would be triggered by a final disapproval of this portion of Arizona's infrastructure SIP. EPA will continue to work with Arizona to incorporate emission limits to address the requirements of the Regional Haze Rule into the Arizona SIP. For further discussion of our analysis of prong 4, please see the TSD associated with this proposal and in the docket for today's rulemaking.

IV. Proposed Action

EPA is proposing to approve Arizona's SIP as meeting the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) prongs 1 and 2 for the 2008 ozone NAAQS. EPA is proposing this approval based on the overall weight of evidence from information and analysis provided by Arizona, as well as the recent air quality modeling released in EPA's August 4, 2015 NODA, and other data analysis that confirms that emissions from Arizona will not contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in California or any other state.

EPA is proposing to disapprove Arizona's SIP with respect to the interstate transport requirements of CAA section 110(a)(2)(D)(i)(II) prong 4 for the 2008 ozone NAAQS. Because Arizona's 2012 and 2015 submittals rely, in part, on FIPs to address interstate transport visibility requirements, they do not meet the requirements of this portion of CAA § 110(a)(2)(D) for the 2008 ozone NAAQS. However, because FIPs are already in place, no additional FIP obligation would be triggered by a final disapproval of this portion of Arizona's infrastructure SIP. EPA will continue to work with Arizona to incorporate emission limits to address the requirements of the Regional Haze Rule into the Arizona SIP.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA because this action does not impose additional requirements beyond those imposed by state law.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities beyond those imposed by state law.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action does not impose additional requirements beyond those imposed by state law. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, will result from this action.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not impose additional requirements beyond those imposed by state law.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

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[18] Arizona State Implementation Plan, Regional Haze Under Section 308 of the Federal Regional Haze Rule (January 2011), section 12.4.1.

[19] FIP promulgated at 77 FR 72514 (December 5, 2012).

[20] *Id.*

[21] FIP promulgated at 79 FR 5240 (September 3, 2014).

[22] *Id.*

[23] *Id.*

[24] *Id.*

[25] SIP approval promulgated for Unit 1 and FIP promulgated for Units 2 and 3 at 77 FR 72511 (December 5, 2012). SIP revision for emissions limits for Unit 1 and SIP approval for Units 2 and 3 promulgated at 80 FR 19220 (April 10, 2015).

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J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population

The EPA lacks the discretionary authority to address environmental justice in this rulemaking.

List of Subjects in 40 CFR Part 52

Air pollution control, Approval and promulgation of implementation plans, Environmental protection, Incorporation by reference, Oxides of nitrogen, Ozone, and Volatile organic compounds.

Dated: March 15, 2016.

Jared Blumenfeld,

Regional Administrator, Region IX.

[FR Doc. 2016–06438 Filed 3–21–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52

[EPA–R04–OAR–2015–0798; FRL–9943–88–Region 4]

Air Plan Disapprovals; MS; Prong 4–2008 Ozone, 2010 NO_2, SO_2, and 2012 $PM_{2.5}$

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to disapprove the visibility transport (prong 4) portions of revisions to the Mississippi State Implementation Plan (SIP), submitted by the Mississippi Department of Environmental Quality (MDEQ), addressing the Clean Air Act (CAA or Act) infrastructure SIP requirements for the 2008 8-hour Ozone, 2010 1-hour Nitrogen Dioxide (NO_2), 2010 1-hour Sulfur Dioxide (SO_2), and 2012 annual Fine Particulate Matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS). The CAA requires that each state adopt and submit a SIP for the implementation, maintenance, and enforcement of each NAAQS promulgated by EPA, commonly referred to as an ''infrastructure SIP.'' Specifically, EPA is proposing to disapprove the prong 4 portions of Mississippi's May 29, 2012, 2008 8-hour Ozone infrastructure SIP submission; July 26, 2012, 2008 8-hour Ozone infrastructure SIP resubmission; February 28, 2013, 2010 1-hour NO_2 infrastructure SIP submission; June 20, 2013, 2010 1-hour SO_2 infrastructure SIP submission; and December 8, 2015, 2012 annual $PM_{2.5}$ infrastructure SIP submission. All other applicable infrastructure requirements for these SIP submissions have been or will be addressed in separate rulemakings.

DATES: Comments must be received on or before April 21, 2016.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R04–OAR–2015–0798 at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Sean Lakeman of the Air Regulatory Management Section, Air Planning and Implementation Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Mr. Lakeman can be reached by telephone at (404) 562–9043 or via electronic mail at *lakeman.sean@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

By statute, SIPs meeting the requirements of sections 110(a)(1) and (2) of the CAA are to be submitted by states within three years after promulgation of a new or revised NAAQS to provide for the implementation, maintenance, and enforcement of the new or revised NAAQS. EPA has historically referred to these SIP submissions made for the purpose of satisfying the requirements of sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' submissions. Sections 110(a)(1) and (2) require states to address basic SIP elements such as for monitoring, basic program requirements, and legal authority that are designed to assure attainment and maintenance of the newly established or revised NAAQS. More specifically, section 110(a)(1) provides the procedural and timing requirements for infrastructure SIPs. Section 110(a)(2) lists specific elements that states must meet for the infrastructure SIP requirements related to a newly established or revised NAAQS. The contents of an infrastructure SIP submission may vary depending upon the data and analytical tools available to the state, as well as the provisions already contained in the state's implementation plan at the time in which the state develops and submits the submission for a new or revised NAAQS.

Section 110(a)(2)(D) has two components: 110(a)(2)(D)(i) and 110(a)(2)(D)(ii). Section 110(a)(2)(D)(i) includes four distinct components, commonly referred to as ''prongs,'' that must be addressed in infrastructure SIP submissions. The first two prongs, which are codified in section 110(a)(2)(D)(i)(I), are provisions that prohibit any source or other type of emissions activity in one state from contributing significantly to nonattainment of the NAAQS in another state (prong 1) and from interfering with maintenance of the NAAQS in another state (prong 2). The third and fourth prongs, which are codified in section 110(a)(2)(D)(i)(II), are provisions that prohibit emissions activity in one state from interfering with measures required to prevent significant deterioration of air quality in another state (prong 3) or from interfering with measures to protect visibility in another state (prong 4). Section 110(a)(2)(D)(ii) requires SIPs to include provisions insuring compliance with sections 115 and 126 of the Act, relating to interstate and international pollution abatement.

Through this action, EPA is proposing to disapprove the prong 4 portions of Mississippi's infrastructure SIP submissions for the 2008 8-hour Ozone, 2010 1-hour NO_2, 2010 1-hour SO_2, and 2012 annual $PM_{2.5}$ NAAQS. All other applicable infrastructure SIP requirements for these SIP submissions have been or will be addressed in separate rulemakings. A brief background regarding the NAAQS relevant to today's proposal is provided below. For comprehensive information on these NAAQS, please refer to the **Federal Register** notices cited in the following subsections.

a. 2008 8-Hour Ozone NAAQS

On March 12, 2008, EPA revised the 8-hour Ozone NAAQS to 0.075 parts per million. *See* 73 FR 16436 (March 27, 2008). States were required to submit infrastructure SIP submissions for the

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EPA-APPROVED ALASKA REGULATIONS AND STATUTES

State citation	Title/subject	State effective date	EPA approval date	Explanations
Alaska Administrative Code Title 18 Environmental Conservation, Chapter 50 Air Quality Control (18 AAC 50)				
* * * * * * *				
18 AAC 50.010	Ambient Air Quality Standards	4/17/15	5/19/16, [Insert **Federal Register** citation].	except (7) and (8).
18 AAC 50.015	Air Quality Designations, Classifications, and Control Regions.	4/17/15	5/19/16, [Insert **Federal Register** citation].	
18 AAC 50.020	Baseline Dates and Maximum Allowable Increases.	4/17/15	5/19/16, [Insert **Federal Register** citation].	
* * * * * * *				
18 AAC 50.035	Documents, Procedures and Methods Adopted by Reference.	4/17/15	5/19/16, [Insert **Federal Register** citation].	except (a)(6) and (b)(4).
18 AAC 50.040	Federal Standards Adopted by Reference.	4/17/15; 11/9/14	5/19/16, [Insert **Federal Register** citation]; 1/7/15, 80 FR 832.	except (a), (b), (c), (d), (e), (g), (j), and (k).
* * * * * * *				
18 AAC 50.215	Ambient Air Quality Analysis Methods.	4/17/15	5/19/16, [Insert **Federal Register** citation].	except (a)(4).
* * * * * * *				

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■ 3. Section 52.96 is amended by revising paragraph (a) to read as follows:

§ 52.96 Significant deterioration of air quality.

(a) The State of Alaska Department of Environmental Conservation Air Quality Control Regulations are approved as meeting the requirements of 40 CFR 51.166 and part C for preventing significant deterioration of air quality. The specific provisions approved are: 18 AAC 50.010 except (7) and (8); 18 AAC 50.015; 18 AAC 50.020; 18 AAC 50.035(a)(4), (a)(5), and (b)(1); 18 AAC 50.040(h); and 18 AAC 50.215 except (a)(4) as in effect on April 17, 2015; 18 AAC 50.990 as in effect on November 9, 2014; 18 AAC 50.306 as in effect on January 4, 2013; 18 AAC 50.345 except (b), (c)(3), and (l) as in effect on September 14, 2012; and 18 AAC 50.250 as in effect on October 1, 2004.

* * * * *

[FR Doc. 2016–11626 Filed 5–18–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2015–0793; FRL–9946–58–Region 9]

Partial Approval and Partial Disapproval of Air Quality State Implementation Plans; Arizona; Infrastructure Requirements To Address Interstate Transport for the 2008 Ozone NAAQS

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving in part and disapproving in part State Implementation Plan (SIP) revisions submitted by the Arizona Department of Environmental Quality to address the interstate transport requirements of Clean Air Act (CAA or Act) section 110(a)(2)(D)(i) with respect to the 2008 ozone national ambient air quality standard (NAAQS). We are approving the portion of the Arizona SIP pertaining to significant contribution to nonattainment or interference with maintenance in another state and disapproving the portion of Arizona's SIP pertaining to interstate transport visibility requirements. Where EPA is disapproving a portion of the Arizona SIP revision, the deficiencies have already been addressed by a federal implementation plan (FIP).

DATES: This final rule is effective on June 20, 2016.

ADDRESSES: EPA has established docket number EPA–R09–OAR–2015–0793 for this action. Generally, documents in the docket for this action are available electronically at *http://www.regulations.gov* or in hard copy at EPA Region IX, 75 Hawthorne Street, San Francisco, California 94105–3901. While all documents in the docket are listed at *http://www.regulations.gov,* some information may be publicly available only at the hard copy location (*e.g.,* copyrighted material, large maps, multi-volume reports), and some may not be available in either location (*e.g.,* confidential business information (CBI)). To inspect the hard copy materials, please schedule an appointment during normal business hours with the contact listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Tom Kelly, Air Planning Office (AIR–2), U.S. Environmental Protection Agency, Region IX, (415) 972–3856, *kelly.thomasp@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, the terms ''we,'' ''us,'' and ''our'' refer to EPA.

Table of Contents

I. Background

CAA sections 110(a)(1) and (2) require states to address basic SIP requirements to implement, maintain and enforce the NAAQS no later than three years after the promulgation of a new or revised standard. Section 110(a)(2) outlines the specific requirements that each state is required to address in this SIP submission that collectively constitute the ''infrastructure'' of a state's air quality management program. SIP submittals that address these requirements are referred to as ''infrastructure SIPs'' (I–SIP). In particular, CAA section 110(a)(2)(D)(i)(I) requires that each SIP for a new or revised NAAQS contain adequate provisions to prohibit any source or other type of emissions activity within the state from emitting air pollutants that will ''contribute significantly to nonattainment'' (prong 1) or ''interfere with maintenance'' (prong 2) of the applicable air quality standard in any other state. CAA section 110(a)(2)(D)(i)(II) requires SIP provisions that prevent interference with measures required to be included in the applicable implementation plan for any other State under part C to prevent significant deterioration of air quality (prong 3) or to protect visibility (prong 4). This action addresses the section 110(a)(2)(D)(i) requirements of prongs 1, 2 and 4 with respect to Arizona's I–SIP submissions.

On March 27, 2008, EPA issued a revised NAAQS for ozone.[1] This action triggered a requirement for states to submit an I–SIP to address the applicable requirements of section 110(a)(2) within three years of issuance of the revised NAAQS. On December 27, 2012, the Arizona Department of Environmental Quality (ADEQ) submitted its 2008 ozone NAAQS I–SIP. On December 3, 2015, ADEQ submitted a supplement to the 2012 submittal further addressing 110(a)(2)(D)(i) prongs 1, 2, and 4.[2]

On July 14, 2015, EPA partially approved and partially disapproved Arizona's 2012 submittal for the 2008 ozone NAAQS for the I–SIP elements C, D, J, and K. EPA partially approved and partially disapproved the submittal for purposes of 110(a)(2)(D)(i)(II) prong 3 and partially approved and partially disapproved the submittal for purposes of 110(a)(2)(D)(ii) (relating to CAA sections 115 and 126).[3] We subsequently took action on I–SIP elements A, B, E–H, L, and M for the 2008 ozone NAAQS on August 10, 2015.[4] We also stated our intention to propose action on the I–SIP submittal for the 2008 ozone NAAQS 110(a)(2)(D)(i) prongs 1, 2, and 4 in an additional action.[5] Additionally, pursuant to a judgment issued by the Northern District of California in *Sierra Club* vs. *McCarthy,* EPA must take final action on 110(a)(2)(D) prongs 1, 2, and 4 of Arizona's December 2012 SIP revision by June 7, 2016.[6]

On March 22, 2016, EPA proposed to approve in part, and disapprove in part, the 2012 and 2015 SIP revisions addressing the infrastructure requirements of CAA section 110(a)(2)(D)(i) for the 2008 ozone NAAQS.[7] The rationale supporting EPA's actions is explained in our proposal notice and the associated TSD and will not be restated here. The proposed rule and TSD are available online at *http://www.regulations.gov,* Docket ID number EPA–R09–OAR–2015–0793.

II. Public Comments

EPA received no comments on the proposed action during the public comment period.

III. Final Action

Under CAA section 110(k)(3), and based on the evaluation and rationale presented in the proposed rule, the related TSD, and this final rule, EPA is approving in part and disapproving in part Arizona SIP revisions addressing the interstate transport requirements of CAA section 110(a)(2)(D) with respect to the 2008 ozone NAAQS.

EPA is approving Arizona's SIP as meeting the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) prongs 1 and 2 for the 2008 ozone NAAQS. EPA is disapproving Arizona's SIP with respect to the interstate transport requirements of CAA section 110(a)(2)(D)(i)(II) prong 4 for the 2008 ozone NAAQS. However, because EPA has issued Regional Haze FIPs addressing visibility requirements in Arizona, no additional FIP obligation is triggered by the disapproval of this portion of Arizona's infrastructure SIP. EPA will continue to work with Arizona to incorporate emission limits to address the requirements of the Regional Haze Rule into the state SIP.

IV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA because this action does not impose additional requirements beyond those imposed by state law.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities beyond those imposed by state law.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action does not impose additional requirements beyond those imposed by state law. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, will result from this action.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

[1] National Ambient Air Quality Standards for Ozone; Final Rule, 73 FR 16436 (March 27, 2008).

[2] ''Arizona State Implementation Plan Revisions for 2008 Ozone and 2010 Nitrogen Dioxide Under Clean Air Act Section 110(a)(2)(D) . . .'' Signed December 3, 2015. Also see email from Heidi Haggerty of ADEQ: AZ 2015 Ozone Transport I–SIP Submittal Clarification. Sent December 9, 2015.

[3] Partial Approval and Partial Disapproval of Air Quality State Implementation Plans; Arizona; Infrastructure Requirements for Lead and Ozone. 80 FR 40905 (July 14, 2015).

[4] Approval and Promulgation of State Implementation Plans; Arizona; Infrastructure Requirements for the 2008 Lead (Pb) and the 2008 8-Hour Ozone National Ambient Air Quality Standards (NAAQS). 80 FR 47859 (August 10, 2015).

[5] *Id.*

[6] Judgment, Sierra Club v. McCarthy, Case 4:14–cv–05091–YGR (N.D. Cal. May 15, 2015).

[7] Partial Approval and Partial Disapproval of Air Quality State Implementation Plans; Arizona; Infrastructure Requirements to Address Interstate Transport for the 2008 Ozone NAAQS. 81 FR 1520. (March 22, 2016).

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F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not impose additional requirements beyond those imposed by state law.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population

The EPA lacks the discretionary authority to address environmental justice in this rulemaking.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 18, 2016. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Approval and promulgation of implementation plans, Incorporation by reference, Oxides of nitrogen, Ozone, and Volatile organic compounds.

Dated: May 6, 2016.

Deborah Jordan,

Acting Regional Administrator, Region IX.

[FR Doc. 2016–11744 Filed 5–18–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0696; FRL–9944–26–OAR]

RIN 2060–AS86

Technical Amendments to Performance Specification 18 and Procedure 6

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is taking direct final action to make several minor technical amendments to the performance specifications and test procedures for hydrogen chloride (HCl) continuous emission monitoring systems (CEMS). This direct final rule also makes several minor amendments to the quality assurance (QA) procedures for HCl CEMS used for compliance determination at stationary sources. The performance specification (Performance Specification 18) and the QA procedures (Procedure 6) were published in the **Federal Register** on July 7, 2015. These amendments make several minor corrections and clarify several aspects of these regulations.

DATES: This rule is effective on August 17, 2016 without further notice, unless the EPA receives adverse comment by July 5, 2016. If the EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0696, at *http://www.regulations.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, Cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets*.

FOR FURTHER INFORMATION CONTACT: Ms. Candace Sorrell, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Measurement Technology Group (Mail Code: E143–02), Research Triangle Park, NC 27711; telephone number: (919) 541–1064; fax number: (919) 541–0516; email address: *sorrell.candace@epa.gov*.

SUPPLEMENTARY INFORMATION: The information presented in this rule is organized as follows:

and local ventilation) or administrative control measures (*e.g.,* workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (e) (concentration set at 1.0%), (f), (g)(1)(i), (ii) and (iv), (2)(i), (ii) and (v), (3)(i) and (ii), (4)(iii) (above concentration of 1 part per billion (ppb), and (5). Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(g). It is a significant new use to manufacture, process, or use the substance that results in inhalation exposure. It is a significant new use to manufacture, process and use the substance other than as stated in the PMN.

(iv) *Disposal.* Residuals must be recycled back into the process as stated in the PMN.

(v) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), (c)(4), where N=1.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (k) are applicable to manufacturers and processors of this substance.

(2) *Limitations or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

(3) *Determining whether a specific use is subject to this section.* The provisions of § 721.1725(b)(1) apply to paragraphs (a)(2)(iii) and (iv) of this section.

§ 721.11246 Substituted alkanediol, polymer with heteromonocycles, alkenoate, metal complexes (generic).

(a) Chemical substance and significant new uses subject to reporting. (1) The chemical substance identified generically as substituted alkanediol, polymer with heteromonocycles, alkenoate, metal complexes (PMN P– 18–130) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been reacted (cured).

(2) The significant new uses are:

(i) Protection in the workplace. Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3) through (5) and (6)(v) and (vi) (particulate), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4) engineering control measures (*e.g.,* enclosure or confinement of the operation, general and local ventilation) or administrative control measures (*e.g.,* workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health assigned protection factor (APF) of at least 50, or if spray applied an APF of 1000.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), (g)(1)(i) ((sensitization), (mutagenicity)), (2)(i) through (v), and (5). Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f). It is a significant new use to use the substance other than as an adhesion promoter for industrial applications.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers and processors of this substance.

(2) *Limitations or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

[FR Doc. 2019–26224 Filed 12–4–19; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–HQ–OAR–2019–0603; FRL–10002–78–OAR]

Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final action.

SUMMARY: The Environmental Protection Agency (EPA) is taking final action finding that seven states have failed to submit infrastructure State Implementation Plans (SIPs) to satisfy certain interstate transport requirements of the Clean Air Act (CAA) with respect to the 2015 8-hour ozone national ambient air quality standards (NAAQS). Specifically, these requirements pertain to prohibiting significant contribution to nonattainment, or interference with maintenance, of the 2015 8-hour ozone NAAQS in other states. These findings of failure to submit establish a 2-year deadline for the EPA to promulgate Federal Implementation Plans (FIPs) to address these interstate transport requirements for a given state unless, prior to the EPA promulgating a FIP, the state submits, and the EPA approves, a SIP that meets these requirements.

DATES: Effective date of this action is January 6, 2020.

FOR FURTHER INFORMATION CONTACT: General questions concerning this document should be addressed to Mr. Thomas Uher, Office of Air Quality Planning and Standards, Air Quality Policy Division, Mail Code C539–04, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone (919) 541–5534; email: *uher.thomas@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Notice and Comment Under the Administrative Procedures Act (APA)

Section 553 of the APA, 5 U.S.C. 553(b)(3)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. The EPA has determined that there is good cause for making this final agency action without prior proposal and opportunity for comment because no significant EPA judgment is involved in making a finding of failure to submit SIPs, or elements of SIPs, required by the CAA, where states have made no submissions or incomplete submissions, to meet the requirement. Thus, notice and public procedure are unnecessary. The EPA finds that this constitutes good cause under 5 U.S.C. 553(b)(3)(B).

B. How can I get copies of this document and other related information?

The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2019–0603. All documents in the docket are listed and publicly available at *http://www.regulations.gov*. Publicly available docket materials are also available in hard copy at the Air and Radiation Docket and Information

Center, EPA/DC, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Office of Air and Radiation Docket and Information Center is (202) 566–1742. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at: *http://www.epa.gov/epahome/dockets.htm*.

C. How is the preamble organized?

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D. Where do I go if I have state specific questions?

The table below lists the states that failed to make a complete interstate transport SIP submittal addressing CAA section 110(a)(2)(D)(i)(I) requirements for the 2015 ozone NAAQS. For questions related to specific states mentioned in this document, please contact the appropriate EPA Regional office:

Regional offices	States
EPA Region 1: Alison Simcox, Manager, Air Quality Branch, EPA Region I, 5 Post Office Square, Suite 100, Boston, MA 02109–3912.	Maine, Rhode Island.
EPA Region 3: Joseph Schulingkamp, Air Protection Division, EPA Region III, 1650 Arch Street, Philadelphia, PA 19103–2187.	Pennsylvania, Virginia.
EPA Region 6: Mary Stanton, Chief, Infrastructure and Ozone Section, EPA Region VI, 1201 Elm Street, Suite 500, Dallas, TX 75270.	New Mexico.
EPA Region 8: Adam Clark, EPA Region VIII, Air and Radiation Division, 1595 Wynkoop St., Denver, CO 80202.	South Dakota, Utah.

II. Background and Overview

A. Interstate Transport SIPs

CAA section 110(a) imposes an obligation upon states to submit SIPs that provide for the implementation, maintenance, and enforcement of a new or revised NAAQS within 3 years following the promulgation of that NAAQS. CAA section 110(a)(2) lists specific requirements that states must meet in these SIP submissions, as applicable. The EPA refers to this type of SIP submission as an ''infrastructure'' SIP because it ensures that states can implement, maintain and enforce the new or revised air standards. Within these requirements, CAA section 110(a)(2)(D)(i) contains requirements to address interstate transport of NAAQS pollutants. A SIP revision submitted for this sub-section is referred to as an ''interstate transport SIP.'' In turn, CAA section 110(a)(2)(D)(i)(I) requires that such a plan contain adequate provisions to prohibit emissions from the state that will contribute significantly to nonattainment of the NAAQS in any other state (''prong 1'') or interfere with maintenance of the NAAQS in any other state (''prong 2''). Interstate transport prongs 1 and 2, also called collectively the ''good neighbor'' provision, are the requirements relevant to this findings document.

Pursuant to CAA section 110(k)(1)(B), the EPA must determine no later than 6 months after the date by which a state is required to submit a SIP whether a state has made a submission that meets the minimum completeness criteria established pursuant to CAA section 110(k)(1)(A). These criteria are set forth at 40 CFR part 51, appendix V. The EPA refers to the determination that a state has not submitted a SIP submission that meets the minimum completeness criteria as a ''finding of failure to submit.'' If the EPA finds a state has failed to submit a SIP to meet its statutory obligation to address CAA section 110(a)(2)(D)(i)(I), then pursuant to CAA section 110(c)(1), the EPA has not only the authority, but the obligation, to promulgate a FIP within 2 years to address the CAA requirement. This finding, therefore, starts a 2-year ''clock'' for promulgation by the EPA of a FIP, in accordance with CAA section 110(c)(1), unless prior to such promulgation the state submits, and the EPA approves, a submittal from the state to meet the requirements of CAA section 110(a)(2)(D)(i)(I). Even where the EPA has promulgated a FIP, the EPA will withdraw that FIP if a state submits and the EPA approves a SIP satisfying the relevant requirements. The EPA notes this action does not start a mandatory sanctions clock pursuant to CAA section 179 because this finding of failure to submit does not pertain to a part D plan for nonattainment areas required under CAA section 110(a)(2)(I) or a SIP call pursuant to CAA section 110(k)(5).

B. Background on 2015 Ozone NAAQS and Related Matters

On October 1, 2015, the EPA promulgated a new 8-hour primary and secondary ozone NAAQS of 70 parts per billion (ppb), which is met when the 3-year average of the annual fourth highest daily maximum 8-hour concentration does not exceed 70 ppb.[1] Pursuant to the 3-year period provided in CAA section 110(a)(1), infrastructure SIPs addressing the revised standard were due on October 1, 2018.

On September 5, 2019, the EPA announced via its website its intention to make findings that certain states have failed to submit complete interstate

[1] *See* Final Rule, National Ambient Air Quality Standards for Ozone, 80 FR 65292 (October 26, 2015).

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transport SIPs for the 2015 ozone NAAQS by November 22, 2019.[2]

On September 30, 2019, the Sierra Club filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) alleging that the EPA had not fulfilled its mandatory duty to make findings of failure to submit interstate transport SIPs pursuant to CAA section 110(a)(2)(D)(i)(I) with respect to the 2015 ozone NAAQS for twelve states: Arkansas, Hawaii, Louisiana, Maine, Maryland, Mississippi, New Mexico, Pennsylvania, Rhode Island, Utah, Vermont, and Virginia.[3] On October 29, 2019, the States of New Jersey and Connecticut filed a complaint in the D.C. District Court alleging that the EPA had not fulfilled its mandatory duty to make findings of failure to submit interstate transport SIPs addressing interstate transport in CAA section 110(a)(2)(D)(i)(I) with respect to the 2015 ozone NAAQS for two states: Virginia and Pennsylvania.[4]

To fulfill its statutory obligations, the EPA is taking this action for all states that have failed to submit complete SIPs addressing CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS, not just those states named in the complaints. As explained below, in total, seven states have failed to submit complete SIPs while forty-three states and the District of Columbia have submitted complete SIPs addressing CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

The EPA has included in the docket for this action its correspondence with states regarding the completeness of their SIP submissions. SIPs may be considered complete by either of two methods. First, the EPA may make a determination that a SIP is complete under the ''completeness criteria'' set out at 40 CFR part 51, appendix V. *See* CAA section 110(k)(1). Second, a SIP may be deemed complete by operation of law if the EPA has failed to make such a determination by 6 months after receipt of the SIP submission. *See* CAA section 110(k)(1)(B).

Five states failed to make any SIP submittal addressing interstate transport for the 2015 ozone NAAQS: Maine, New Mexico, Pennsylvania, Rhode Island, and Virginia. All of these states were identified in the Sierra Club complaint.

The EPA has evaluated the SIP submittals of two states, South Dakota and Utah, for completeness pursuant to the criteria in 40 CFR part 51, appendix V, and concluded that these are incomplete SIP submissions.[5] On November 21, 2019, the EPA sent letters to these two states explaining our incompleteness determination. These letters are included in the docket for this action. As explained in those letters, the completeness criteria under 40 CFR part 51, appendix V, section 2.1(g), require a certification that public hearing(s) were held in accordance with the information provided in the state's public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 51.102. Under § 51.102(a), states must either hold a public hearing or provide the public the opportunity to request a public hearing. South Dakota and Utah did not provide the necessary certification under section 2.1(g) of appendix V that a public hearing was held or that they had provided the opportunity for the public to request a public hearing in accordance with 40 CFR 51.102(a). As a result, the EPA determined that these SIP submissions are incomplete. Where the EPA determines that a SIP submission does not meet the appendix V completeness criteria, ''the State shall be treated as not having made the submission............'' CAA section 110(k)(1)(C). Accordingly, the EPA is finding in this document that South Dakota and Utah have failed to submit complete SIP revisions addressing CAA section 110(a)(2)(D)(i)(I) as to the 2015 ozone NAAQS. These states may, if they choose, resubmit to the EPA complete SIPs, which the EPA will review and act upon at a later date.

In all other cases, the EPA has determined that the SIP submittals are complete or they have been deemed complete by operation of law. In particular, the six remaining states identified in Sierra Club's complaint filed in the D.C. District Court have made complete SIP submittals addressing the good neighbor provision for the 2015 ozone NAAQS: Arkansas, Hawaii, Louisiana, Maryland, Mississippi, and Vermont. As a result, there is no longer a basis to make findings of failure to submit for these states.

The EPA is issuing national findings of failure to submit interstate transport SIPs addressing the requirements of CAA section 110(a)(2)(D)(i)(I) as to the 2015 ozone NAAQS, for all states that have not made complete submissions as of the date of this document.

III. Findings of Failure To Submit for States That Failed To Make an Interstate Transport SIP Submission for the 2015 Ozone NAAQS

The EPA is making findings of failure to submit for seven states. The EPA finds the following states have not submitted complete interstate transport SIPs to meet the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS: Maine, New Mexico, Pennsylvania, Rhode Island, South Dakota, Utah, and Virginia. Notwithstanding these findings, and the associated obligation of the EPA to promulgate FIPs for these states within two years of this finding, the EPA intends to continue to work with states subject to these findings in order to provide assistance as necessary to help them develop approvable SIP submittals in a timely manner.

IV. Environmental Justice Considerations

This document is making a procedural finding that certain states have failed to submit a SIP to address CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The EPA did not conduct an environmental analysis for this action because it would not directly affect the air emissions of particular sources. Because this action will not directly affect the air emissions of particular sources, it does not affect the level of protection provided to human health or the environment. Therefore, this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations.

V. Statutory and Executive Order Reviews

A. Executive Orders 12866: Regulatory Planning and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is not an Executive Order 13771 regulatory action because it finds that seven states failed to submit a SIP to meet their statutory obligation to address CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

C. Paperwork Reduction Act

This action does not impose an information collection burden under the

[2] U.S. EPA, Interstate Air Pollution Transport, *https://www.epa.gov/airmarkets/interstate-air-pollution-transport.*

[3] Complaint, *Sierra Club* v. *Wheeler,* No. 1:19–cv–02923 (D.D.C. filed Sept. 30, 2019).

[4] Complaint, *State of New Jersey* v. *Wheeler,* No. 1:19–cv–03247 (D.D.C. filed Oct. 29, 2019).

[5] Utah was identified in the Sierra Club complaint, but South Dakota was not.

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provisions of the Paperwork Reduction Act. This final action does not establish any new information collection requirement apart from what is already required by law. This finding relates to the requirement in the CAA for states to submit SIPs under section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS.

D. Regulatory Flexibility Act (RFA)

This action is not subject to the RFA. The RFA applies only to rules subject to notice and comment rulemaking requirements under the Administrative Procedure Act (APA), 5 U.S.C. 553 or any other statute. This action is not subject to notice and comment requirements because the agency has invoked the APA ''good cause'' exemption under 5 U.S.C. 553(b). I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. The action is a finding that the named states have not made the necessary SIP submission for interstate transport to meet the requirements under section 110(a)(2)(D)(i)(I) of the CAA.

E. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA 2 U.S.C. 1531–1538 and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action finds that seven states have failed to complete the requirement in the CAA to submit SIPs under section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS. No tribe is subject to the requirement to submit a transport SIP under section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it is a finding that certain states have failed to submit a complete SIP that satisfies interstate transport requirements under section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS and does not directly or disproportionately affect children.

I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

J. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations. In finding that certain states have failed to submit a complete SIP that satisfies the interstate transport requirements under section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS, this action does not adversely affect the level of protection provided to human health or the environment.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

M. Judicial Review

Section 307(b)(l) of the CAA indicates which federal Courts of Appeal have venue for petitions of review of final actions by the EPA under the CAA. This section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if: (i) The agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

This final action is nationally applicable. To the extent a court finds this final action to be locally or regionally applicable, the EPA finds that this action is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). This final action consists of findings of failure to submit required interstate transport SIPs for the 2015 ozone NAAQS from seven states located in four of the ten EPA Regional offices and five different federal judicial circuits. This final action is also based on a common core of factual findings concerning the receipt and completeness of the relevant SIP submittals. For these reasons, this final action is nationally applicable or, alternatively, to the extent a court finds this action to be locally or regionally applicable, the Administrator has determined that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit within 60 days from the date this final action is published in the **Federal Register**. Filing a petition for reconsideration by the Administrator of this final action does not affect the finality of the action for the purposes of judicial review nor does it extend the time within which a petition for judicial review must be filed and shall not postpone the effectiveness of such rule or action. Thus, any petitions for review of this action must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date this final action is published in the **Federal Register**.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements.

NMED Exhibit 7j

Dated: November 22, 2019.

Anne L. Idsal,

Acting Assistant Administrator.

[FR Doc. 2019–26136 Filed 12–4–19; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2018–0623; FRL–10000–33]

Propamocarb; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of propamocarb (also referred to as propamocarb hydrochloride (HCl) in this document) in or on guava, starfruit, the leafy greens subgroup 4–16A, the tuberous and corm vegetable subgroup 1C, and the fruiting vegetable group 8–10. Interregional Research Project Number 4 (IR–4) requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective December 5, 2019. Objections and requests for hearings must be received on or before February 3, 2020, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2018–0623, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Michael Goodis, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Publishing Office's e-CFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2018–0623 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before February 3, 2020. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2018–0623, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.* Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of December 21, 2018 (83 FR 65660) (FRL–9985–67), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 8E8692) by IR–4, IR–4 Project Headquarters, Rutgers, The State University of New Jersey, 500 College Road East, Suite 201 W, Princeton, NJ 08540. The petition requested that 40 CFR part 180 be amended by establishing tolerances for residues of the propamocarb (propyl N-[3-(dimethylamino)propyl]carbamate in or on the following raw agricultural commodities: Guava at 0.05 parts per million (ppm); starfruit at 0.05 ppm; leafy greens subgroup 4–16A at 150 ppm; vegetable, tuberous and corm, subgroup 1C at 0.30 ppm; and vegetable, fruiting, group 8–10 at 4.0 ppm. The petition also requested to amend 40 CFR 180.499 by removing the established tolerances for the residues of propamocarb in or on lettuce, head at 50 ppm; lettuce, leaf at 90 ppm; potato at 0.30 ppm; and vegetable, fruiting, group 8 at 2.0 ppm. That document referenced a summary of the petition prepared by Bayer CropScience, the registrant, which is available in the docket, *http://www.regulations.gov.* There were no comments received in response to the notice of filing.

EPA is establishing tolerances that vary slightly from what was requested to be consistent with Organization for Economic Cooperation and Development (OECD) Rounding Class Practice.

III. Aggregate Risk Assessment and Determination of Safety

Section 408(b)(2)(A)(i) of FFDCA allows EPA to establish a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA

NMED Exhibit 7j